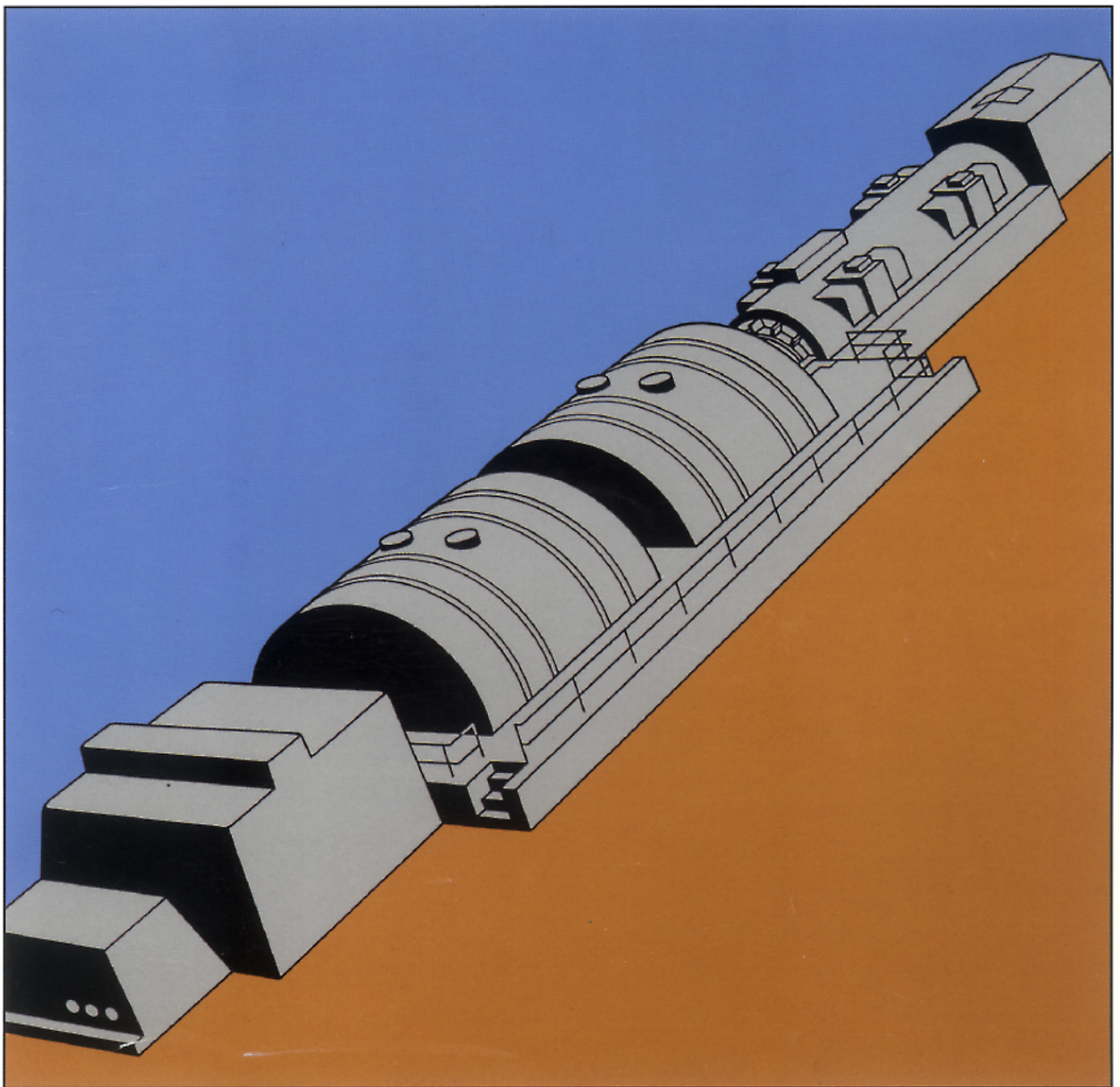


VOLUME 1

ELECTRIC GENERATORS



ELECTRIC POWER RESEARCH INSTITUTE

VOLUME 1

ELECTRIC GENERATORS

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FOREWORD

■ In the past, several electrical equipment manufacturers published reference books dealing with specific technical areas. Many utilities have stated that these reference books have been very useful to them in dealing with plant emergencies and in making decisions on design, system planning, and preventive maintenance.

Unfortunately, manufacturers today seldom publish or update reference books on electric power apparatus, mainly because of tighter budget constraints. Until now, utilities have had no up-to-date industrywide practical reference manual covering the various electric power apparatus and electrical phenomena commonly encountered in power plants. The Power Plant Electrical Reference Series was planned to fill this need.

EPRI believes that the series will save utilities time and money. It will aid plant engineers in

- Prevention of forced outages through proper installation, application, and protection of station auxiliary equipment
- Recognition of potential problems and their prevention
- Selection of appropriate methods of maintenance to ensure trouble-free equipment operation
- Reduction of equipment installation time and expense
- Proper specification of equipment being ordered
- Better coordination and integration of system components

This volume deals with generators. Old or new, the useful life of a generator depends on a careful regimen of operation and maintenance. This regimen includes operational procedures for prewarming, synchronizing, and monitoring and maintenance practices, such as inspection and testing, proper lubrication, and repair. This volume was written to meet these needs; it highlights pertinent information and adds to the existing literature on generators.

A wealth of information about generators is available in ANSI/IEEE and NEMA standards. EPRI has also published much information on generators.

The purpose of this book is to bring out the concepts that are most useful to power plant personnel without requiring an understanding of the rigorous engineering analysis in the basic design of ac generators. This work is expected to guide the user in applying industry standards and references for easier understanding of power plant requirements.

D. K. Sharma

Electrical Systems Division
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ABSTRACT

■ The steam- or gas-turbine-driven generator is either a two-pole or a four-pole machine (3600 or 1800 rpm, 60 Hz), whereas a water-turbine- or engine-driven generator is a multiple-pole, slower-speed machine. This volume describes the basic construction of these generators and describes machine ratings, electrical characteristics, insulation, cooling, and requirements for auxiliary equipment.

The volume presents various excitation systems and their effects on generator operation for over-excited and underexcited field conditions. It discusses operating modes, instrumentation, and monitoring requirements. The maintenance, inspection, and testing programs covered are based on many years of industry experience with operating units. Because generator rotors and stators are sensitive to storage requirements, methods of protecting this equipment in storage are also described.

ACKNOWLEDGMENTS

This volume is the culmination of many years' experience in the electric utility industry. The author wishes to thank individuals at Ohio Power Company's Philo plant—too numerous to mention here—who were most patient and helpful, as well as colleagues at American Electric Power Service Corporation. The author also thanks colleagues in the IEEE Rotating Machinery Committee (RMC), RMC Insulation Subcommittee, and many working groups for many years of informative and challenging work, which provided an opportunity to learn the subject in depth.

Special thanks are extended to A. F. Bristor, D. R. Albright, R. L. Winchester, C. A. Bucci, W. Wilson, H. O. Ohmstedt, G. Wolff, R. E. Fenton, J. M. Brown, and J. A. Massingill of General Electric Company and to G. D. Cooper, R. A. Towne, A. W. Zwiener, R. J. Hillen, R. M. Sexton, J. S. Johnson, P. S. Johrde, and C. Meck of Westinghouse Electric Corporation.

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EXECUTIVE SUMMARY

■ The ac generator has proven to be one of the most reliable components of a power system. Generator reliability, however, depends on three factors: proper application, operation, and regular maintenance. Operators must be aware of the limits imposed by the generator's capability curve and must be extremely careful when synchronizing a generator. The temperature, pressure, humidity, and purity of hydrogen cooling systems warrant careful control and monitoring, as do the temperature, pressure, and conductivity of stator water systems. A program of regular inspection and maintenance may prevent in-service failures and costly repairs; most generator manufacturers recommend rotor removal, visual inspection, and electrical tests on a three- to five-year schedule. This volume describes the procedures for proper operation of a generator and details a comprehensive maintenance program. Sample forms and checklists are included to assist record keeping for maintenance and storage.

Background

ANSI, IEEE, and NEMA standards provide a wealth of information on generator operation, maintenance, and testing. Until now, however, no single source has brought together the practical application information for generators, excitation systems, bearings, monitoring, operation/misoperation, maintenance, testing, troubleshooting, storage, and spare parts. As generator cooling systems, insulation materials, and excitation systems have changed over the years, the problems associated with these systems have also changed. This volume reviews such problems.

Objectives

This volume is intended to provide a useful guide for generator application, operation, and monitoring; to present maintenance, inspection, and testing programs; to describe generator troubleshooting procedures and detail storage requirements for generator spare parts.

Approach

A national survey of utility requirements yielded pertinent information, and a search of available

literature about generators identified practical information on operation, maintenance, storage, and troubleshooting procedures. The EPRI Review Committee, with members from 11 utilities throughout the United States, and other industry experts reviewed the material for technical accuracy and completeness. The resulting information was the basis for this volume of the Power Plant Electrical Reference Series.

Results

This volume will guide the engineering and operating departments of generating facilities in operating, monitoring, testing, and troubleshooting generators and their associated systems. It will also provide useful methods of record keeping for generator maintenance and storage.

ACRONYMS & ABBREVIATIONS

A	ampere(s)	kVac	kilovolt(s) alternating current
ac	alternating current	kVAR	kilovolt-ampere(s)-reactive
AFNL	ampere(s)-field-no-load	kVdc	kilovolt(s) direct current
amb	ambient	kW	kilowatt(s)
ANSI	American National Standards Institute	lb	pound(s)
arm	armature	lb/in.²	pound(s) per square inch
AVR	automatic voltage regulator	LP	low pressure
bkr	breaker	M	motor
CE	collector end	MΩ	megohm(s)
CO₂	carbon dioxide	mfr	manufacturer
CP	commutating pole	min	minute(s)
cpm	cycles per minute	MP	main pole
CT	current transformer	MVAR	megavolt-ampere(s)-reactive
dc	direct current	MW	megawatt(s)
°C	degrees Celsius	NEMA	National Electrical Manufacturers Association
°F	degrees Fahrenheit	Ω	ohm(s)
E_R	rated line-to-line voltage (rms or effective value) (Eq. 1-3)	p	number of poles (Eq. 1-1)
E_T	ac high-potential test voltage (Eq. 1-3)	PF	power factor
EPRI	Electric Power Research Institute	PI	polarization index
exc	exciter	PM	prime mover
f	frequency of the system to which the generator is connected (Eq. 1-1)	PMG	prime-mover governor or permanent-magnet generator
ft	foot (feet)	psia	pound(s) per square inch absolute
ft³	cubic foot (feet)	psig	pound(s) per square inch gage
gen	generator	PT	potential transformer
gpm	gallons per minute	R₁, R₂	resistance at temperature <i>T</i> ₁ and <i>T</i> ₂ , respectively (Eq. 1-2)
h	hour(s)	RF	radio frequency
H₂	hydrogen	rms	root mean square
H₂O	water	rpm	revolutions per minute
HP	high pressure	RTD	resistance temperature detector
hp	horsepower	s	second(s)
Hz	hertz	SCR	silicon-controlled rectifier
I	charging current in milliamperes (Eq. 1-4)	T₁, T₂	temperature in degrees Celsius (Eq. 1-2)
I₂	negative-sequence current	TC	thermocouple
I_A	per unit current	TE	turbine end
IEEE	Institute of Electrical and Electronics Engineers	temp	temperature
in.	inch(es)	UPS	uninterruptible power supply
in.²	square inch(es)	V	test voltage in kilovolts (Eq. 1-4)
inst	instantaneous	V	volt(s)
IR	insulation resistance	V_A	per unit voltage
K₁	empirical factor (Eq. 1-5)	V_p	momentary peak test voltage across the coil
K_T	correction factor	Vac	volt(s) alternating current
kV	kilovolt(s)	VAR	volt-ampere(s)-reactive
kVA	kilovolt-ampere(s)	Vdc	volt(s) direct current

VLF	very low frequency
VOM	volt-ohm-milliammeters
VPI	vacuum-pressure impregnation
VT	voltage transformer
W	watt(s)
W	watt(s) loss (Eq. 1-4)
yr	year(s)

ELECTRIC GENERATORS

W. J. Sheets

1.1 INTRODUCTION

Properly designed ac generators that are correctly applied, operated within specified limits, monitored closely, and maintained and tested on a regular schedule have proven to be one of the most reliable components in a power plant. In addition, if unit relay protection is correctly applied and the calibration checked on a regular schedule, most generators will survive both internal and external electrical faults. Examples of external faults include faults in the generator bus, unit transformers, and unit auxiliaries transformers.

Generator designers have learned to use copper, magnetic materials, insulation, and support components to maximize the loading of these components, minimize the volume of materials required, and still maintain a high degree of reliability. Since the late 1950s direct cooling methods, such as hydrogen or deionized water in direct contact with the copper, have permitted loading of generators to higher current densities and have decreased the amount of material required per generator kilovolt-ampere. Improvements in core iron characteristics and insulation qualities have also contributed to size reduction of generators while maintaining a high level of reliability.

This volume describes generator construction, identifies operational problems, and suggests maintenance inspections, tests, and repairs to ensure generator reliability.

1.2 DEFINITION OF TERMS

Air gap (gas gap) A separating space between two parts of magnetic material, the combination serving as a path for magnetic flux.

Amortisseur A permanently short-circuited winding consisting of conductors embedded in the pole shoes of a synchronous machine and connected at the ends of the poles but not necessarily connected between poles (damper winding).

Armature The members of an electric machine in which an alternating voltage is generated by virtue of motion relative to a magnetic flux field. In ac generators

the armature is also called the stator winding. In dc machines the armature is the entire rotor.

Bar One half of a single-turn coil.

Blocking A structure or combination of parts, usually of insulating material, formed by hold coils in relative position for mechanical support. Blocking is usually inserted in the end turns to resist forces during running and abnormal conditions.

Bore The surface of a cylindrical hole (for example, stator bore). Bores are measured by diameter.

Bottle To shut off the hydrogen supply to the generator when loads and temperatures are high. When loads are reduced and temperatures drop, the hydrogen pressure also decreases. When the load is resumed and temperatures increase, the hydrogen pressure returns to normal, and the hydrogen supply can be reopened.

Brush A conductor, usually composed in part of some form of carbon, serving to maintain an electric connection between the stationary and moving parts of a machine or apparatus. Note: Brushes are carbon, carbon graphite, electrographite, graphite, and metal graphite.

Bushings Preformed insulated casings, with mechanical seals, that permit passage of a high-potential conductor through the generator housing, which usually acts as the armature terminal.

Coil A unit of a winding that consists of one or more insulated conductors connected in series, surrounded by common insulation, and arranged to link or produce magnetic flux.

Collector rings (slip rings) Metal rings mounted on an electric machine that (through stationary brushes) conducts current into or out of a rotating member.

Commutator A cylindrical ring or disk assembly of conducting members connected to windings or coils. The disk is individually insulated in a supporting structure and has an exposed surface for sliding contact with current-collecting brushes. Note: The commutator is mounted on the moving element of the machine.

Connection Any low-impedance tie between electrically conducting components.

Core (core iron) An element made of magnetic material that serves as part of a path for magnetic flux. In a rotating machine, the core is frequently part of the stator; it is usually a hollow cylinder of laminated magnetic steel, slotted on the inner surface to contain the stator windings. (Some rotating machines have rotor cores.)

Damper winding See Amortisseur.

E-rating The rated line-to-line voltage (rms or effective value).

End winding That portion of a winding extending beyond the slots.

Excitation system The source of field current for the excitation of a principal electric machine, including the means for its control.

Exciter The source of all or part of the field current for the excitation of an electric machine.

Field system The portion of a direct-current or synchronous machine that produces the excitation flux.

Filler (filler strip) Additional insulating material used to ensure a tight depthwise fit in the slot.

Flexibility slots Grooves cut in the pole faces of cylindrical rotors—perpendicular or parallel to the rotor axis—to provide flexibility in the pole axis similar to the flexibility in the winding slot axis.

Flooding The application of viscous resins to the end-winding areas by repeated pumping of the liquid insulating material. Flooding also bonds together the windings, blocking, ties, and supports.

Generator A machine that converts mechanical power into electrical power.

Ground insulation (groundwall) Insulation to ensure the electrical isolation of a winding from the core and mechanical parts of a machine.

Insulation Material or a combination of suitable non-conducting materials that provides electric isolation of two parts at different voltages.

Laminated core An assembly of laminations of magnetic material for use as a magnetic circuit element.

Lamination (punching) A relatively thin member of the stator and rotor core, usually made of sheet material. A complete structure is made by assembling laminations in the required number of layers. In a core that carries alternating magnetic flux, the core material is usually laminated (with insulation on the laminations) to reduce eddy-current losses.

Paintbrushing Erratic changes in rotor-winding temperature recording chart.

Picturing Brush outlines usually noted on the surface of a collector ring or commutator.

Pole (field pole) A structure of magnetic material on which a field coil may be mounted.

Roebel transposition A twisting arrangement of insulated strands in a bar (half coil) wherein the strands cross over at regular intervals through the core length. Because each strand occupies every vertical position, the voltage equalizes in each strand.

Rotor The rotating member of a machine, with shaft. Note: In a direct-current machine with stationary field poles, it is commonly called the armature.

Slot A channel or tunnel opening onto or near the air gap and passing essentially in an axial direction through the rotor or stator core. A slot usually contains the conductors of a winding but may be used exclusively for ventilation.

Stator The portion of a generator that includes and supports the stationary active parts. The stator includes the stationary portions of the magnetic circuit and associated windings and leads. It may, depending on the design, include a frame or shell, winding supports, ventilation circuits, coolers, and temperature detectors.

Strand One of a number of paralleled, insulated conducting elements that constitute one turn of a coil in rotating machinery. The strands are usually separated electrically through all the turns of a multiturn coil. Various types of transposition are employed to reduce the circulation of current among the strands. A strand may have a solid cross section, or it may be hollow to permit the flow of cooling fluid in intimate contact with the conductor (one form of conductor cooling).

Tape A relatively narrow, long, thin flexible fabric, mat, or film or a combination of them with or without binder, usually not over 20 cm wide.

Tooth A projection from a core, separating two adjacent slots, the tip of which forms part of one surface of the air gap.

Turn The basic coil element that forms a single conducting loop comprising one insulated conductor. The conductor may consist of a number of parallel-connected insulated strands or laminations, each strand or lamination being in the form of a wire, rod, strip, or bar depending on its cross section.

Wedge (slot wedge) The element placed above the turns or coil sides in a stator or rotor slot and held in place by the engagement of wedge (slot) grooves along the sides of the coil slot or by projections from the sides of the slot tending to close the top of the slot.

Winding An assembly of coils designed to act in consort to produce a magnetic field or to link a flux field.

1.3 TURBINE GENERATORS

Turbine generators are ac synchronous generators driven by turbines for the production of ac power. The generators can be driven by steam turbines or gas turbines and are similar in construction for both types of prime mover. Synchronous generators are characterized by the fact that in steady state they must run at a precisely constant speed. The speed is given by the expression:

$$\text{rpm} = 120 \frac{f}{p} \quad (\text{Eq. 1-1})$$

Where:

f = frequency of the system to which the generator is connected

p = number of poles

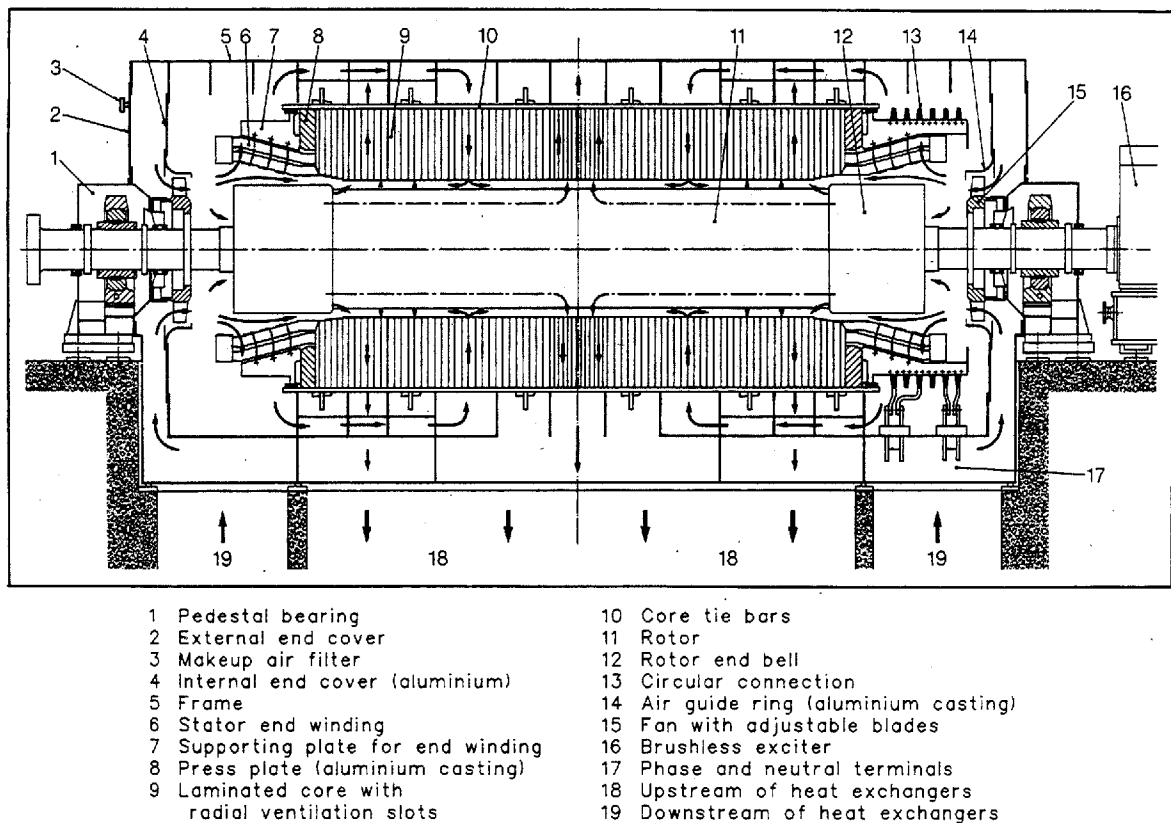
Only 2-pole and 4-pole, 60-Hz generators will be described here. Sizes range from 2 to 1500 MW.

STATOR CONSTRUCTION

The generator consists of a frame or enclosure, stator core and windings, rotor (rotating field) and windings, bearings, coolers, and terminals or bushings to conduct electrical power from the stator windings. Figure 1-1 shows the basic elements of a typical air-cooled generator. Figure 1-2 shows the major parts of an indirectly cooled generator that uses hydrogen as the cooling medium. Note that an indirectly cooled generator was formerly called a conventionally cooled generator. Both terms

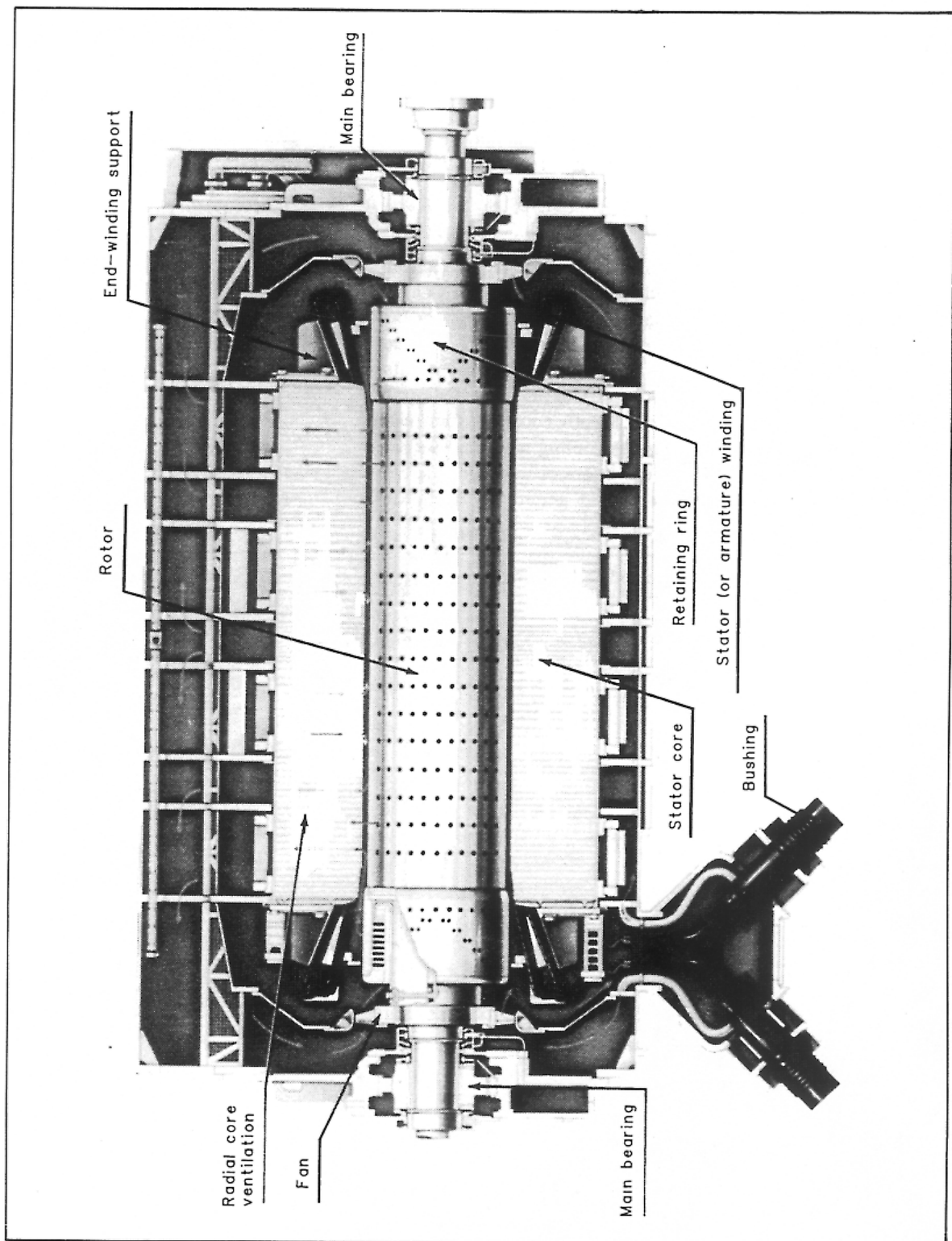
mean that heat from the electrical conductor must flow through the insulation before the heat is carried away by the cooling medium. In contrast, in directly cooled or conductor-cooled or inner-cooled generators, the cooling medium contacts the conductor directly to remove heat. Figure 1-3 shows a direct-hydrogen-inner-cooled generator. Figure 1-4 shows a generator with a water-cooled stator and pressurized rotor.

The rotor windings are normally fed via collector rings from the excitation system to provide a rotating electromagnet that produces flux linking the stator windings to induce stator voltages. The frame is the mechanical enclosure with structural components to support both the stationary and rotating elements of the generator. The enclosure also contains baffles and guides to direct cooling air or hydrogen through the machine. Where hydrogen is used, the enclosure and shaft-sealing system must be capable of withstanding the maximum hydrogen pressure of the design and the



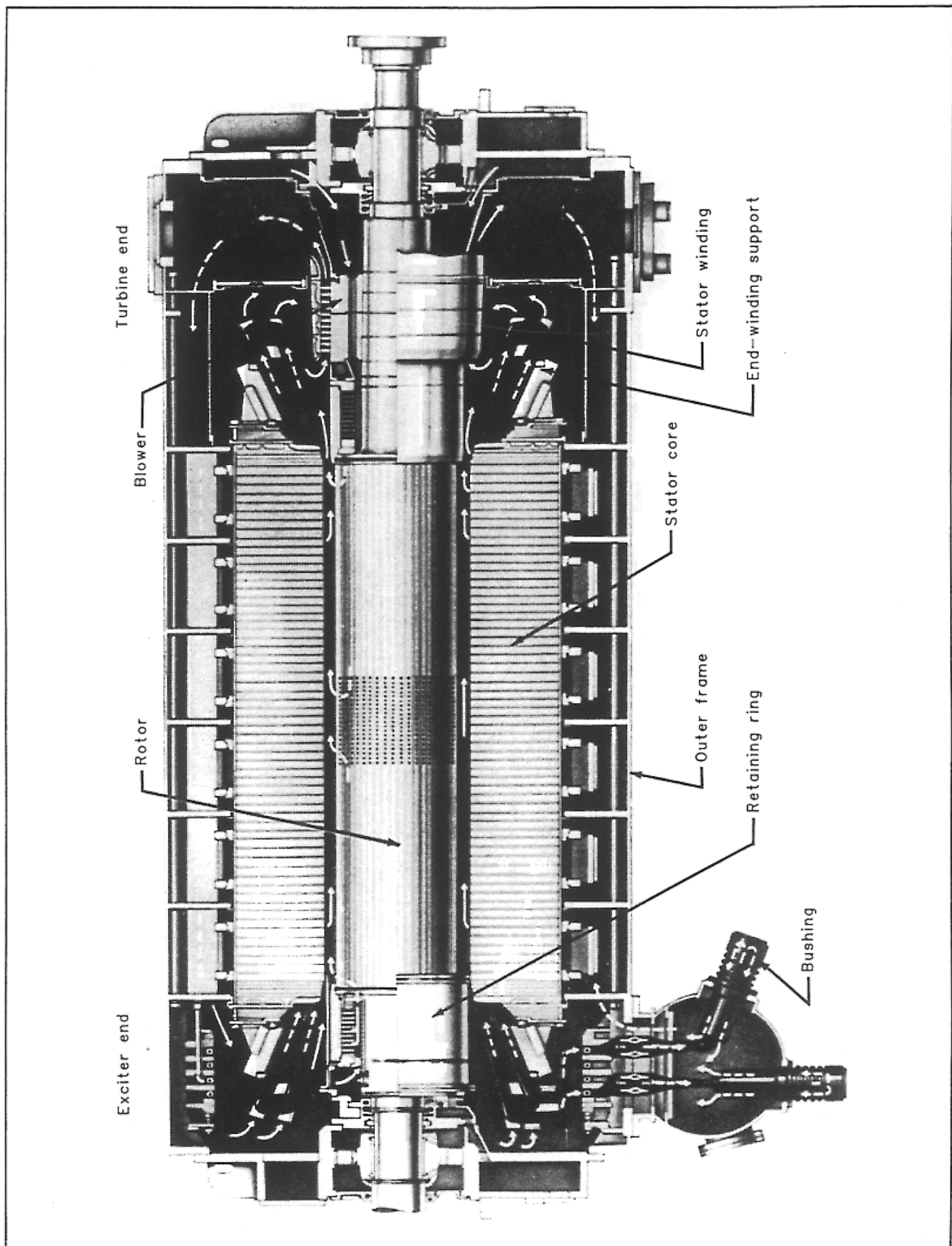
SOURCE: H. Haase, H. Largiadèr, and J. Suter, "Air-Cooled Turbogenerators in the 200-MVA Power Class," *Brown Boveri Review*, March 1986, p. 135, Figure 3.

Figure 1-1 Longitudinal Section of an Air-Cooled Generator



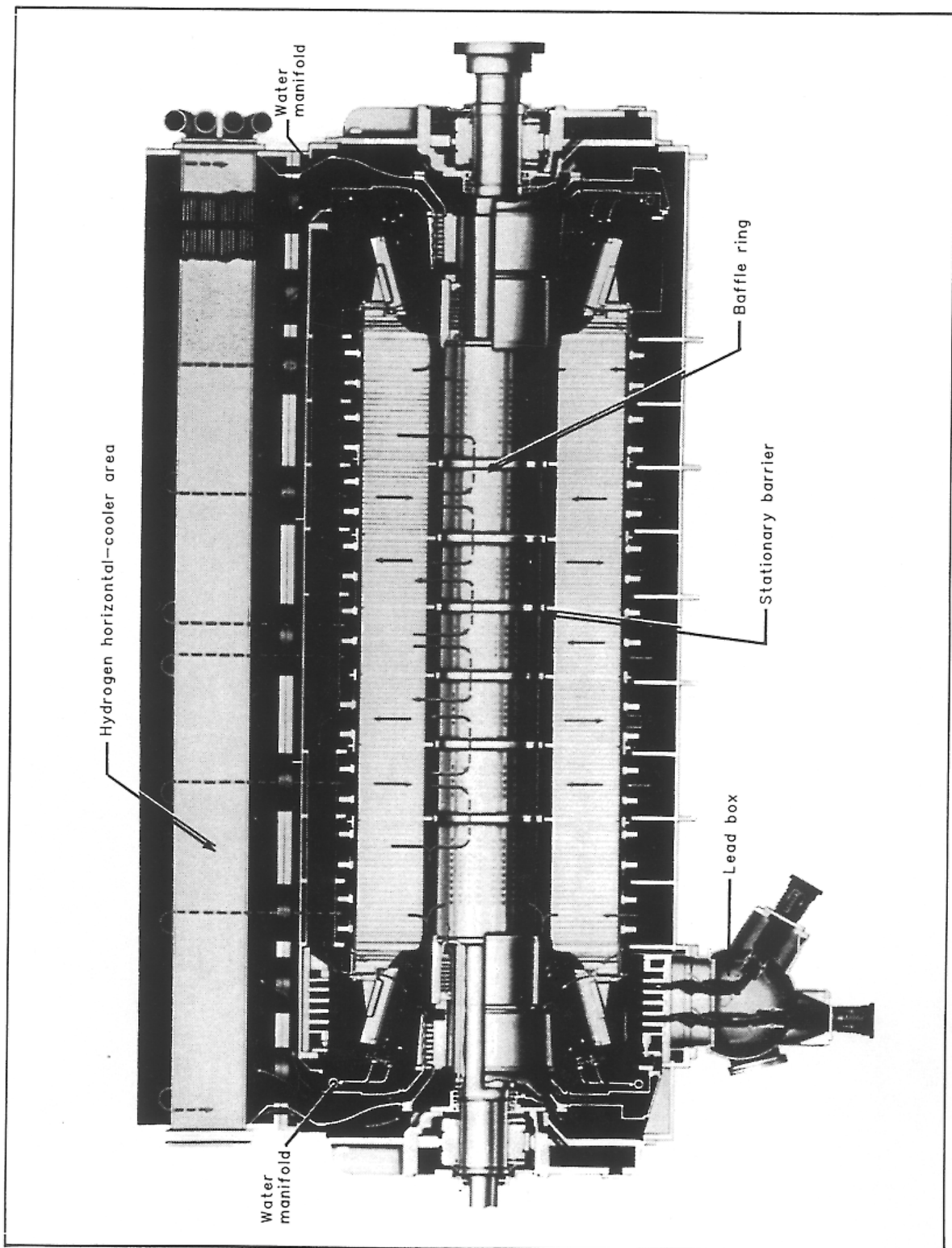
SOURCE: R. W. Beckwith, *Westinghouse Power Systems Marketing Training Guide on Large Electrical Generators*. Pittsburgh, Pa.: Westinghouse Electric Corp., 1979, p. 36, Figure 16.

Figure 1-2 Indirect-Hydrogen-Cooled Generator



SOURCE: R. W. Beckwith, *Westinghouse Power Systems Marketing Training Guide on Large Electrical Generators*. Pittsburgh, Pa.: Westinghouse Electric Corp., 1979, p. 54, Figure 27.

Figure 1-3 3600-rpm-Direct-Hydrogen-Inner-Cooled Generator



SOURCE: R. W. Beckwith, *Westinghouse Power Systems Marketing Training Guide on Large Electrical Generators*. Pittsburgh, Pa: Westinghouse Electric Corp., 1979, p. 51, Figure 25.

Figure 1-4 3600-rpm-Inner-Cooled Generator With Water-Cooled Stator and Pressurized Rotor

shock pressure if a hydrogen explosion occurs. On machines that are totally liquid cooled, cooling circuits and liquid-cooled heat sink fixtures are provided to expedite the removal of heat generated by the inherent electrical and magnetic losses of the machine.

The stator core consists of thin laminations or punchings of silicon steel approximately 0.014 in. thick to minimize eddy-current losses and the resulting heat. The laminations are slotted to receive the stator windings and are insulated from each other with varnish, enamel, or a chemical treatment to limit the flow of eddy currents from one laminate layer to the next. The core is stacked from separate laminations containing one or more slots for stator windings. It is stacked onto stacking bars supported by the frame, which is held in a vertical position. As the core is stacked, pressure is applied regularly to additional laminations to keep the core tight. After the core is completely stacked, final clamping pressure is applied, and the core is permanently clamped with end flanges and clamping fingers, and in some cases, additional insulated axial through-bolts. Core lengths can vary from less than 100 in. (2 poles) up to 330 in. for large 4-pole generators. Stator bores vary from about 36 in. (2 poles) to 76 in. (4 poles).

Two-pole generators have stacking bars at the back of the core. The bars are isolated from the frame by spring devices to isolate the core vibration caused by ovalizing forces. Four-pole machines are not subject to ovalizing forces; therefore the stacking bars are welded to the bore rings (frame).

Stator (or armature) windings have different designs depending on the type of cooling used. Typical winding designs include copper-strand configurations, strand insulation of woven glass or similar insulation, and groundwall insulation of mica flakes, mica mat, or mica paper. The groundwall insulations have backings of fiberglass, Dacron, or similar carriers impregnated with asphalt, epoxy, or polyester resins.

Generator manufacturers often use Roebel transpositions, which shift the strands in the coil or bar as the strands progress down the axis of the machine, so that each strand meets an equal amount of flux and thereby has the same induced voltage. Typical Roebel transpositions are 360° and 540°. End connections may also have transpositions to equalize the strand voltages within the total circuit.

The stacking bars must be well supported in the core slots to prevent movement. The bars in modern machines are heavily loaded by radially outward forces in the slot, up to 68 lb/in.². Therefore

the bars must be locked tightly to the core to prevent motion that will cause fretting of the ground-wall, consequent slot discharge, and further erosion of the groundwall. Surface treatments of the bars—the application of conducting paints in the slots and overlaps of grading paints in the end-winding areas—are also required to prevent electrical discharge.

End-winding supports must be rugged enough to withstand steady-state radial forces and short-circuit forces and to accommodate axial expansion and contraction of the stator windings caused by temperature changes; at the same time, they must maintain the relative tightness of end-winding components to each other.

The stator winding is formed from half-coils or bars in most large turbine generators to provide a single-turn coil. The numbers of top and bottom bars in the slots are each equal to the number of slots in the stator core. The machines are normally Y connected for three phases and may have one or two parallel circuits. For example, a 2-pole generator with two circuits, three phases, and 54 slots would have $54 \text{ slots} / (3 \text{ phases} \times 2 \text{ poles}) = 9 \text{ slots/phase/pole}$. Each circuit would have nine complete coils, each of which includes one top and one bottom bar or half-coil, from line to neutral. A typical circuit is shown in Figure 1-5.

A 4-pole generator with two circuits and 96 slots would have $96 / (3 \text{ phase} \times 4 \text{ poles}) = 8 \text{ slots/phase/pole}$. Each circuit from line to neutral would have 16 complete coils. Line terminals and bushings are normally designated T-1, T-2, and T-3, and the neutral terminals are normally T-4, T-5, and T-6. Volume 8, *Station Protection*, describes methods of grounding the neutral connections and providing ground-fault protection.

CYLINDRICAL ROTOR CONSTRUCTION

The rotor forging normally consists of a solid ingot of high-quality steel that has had slots milled out along the axis of the rotor to accept windings. Windings are usually made of copper conductors. Figure 1-6 shows a typical forging with milled slots.

The windings in each pole consist of multiturn rectangular coils wound symmetrically about the pole centerlines (Figure 1-7). The windings may be solid and designed to transfer heat through the ground insulation to a coolant gas; the gas flows from the ends via subslots and axial cooling passages into the gas gap and back to the coolers.

The windings may be hollow with direct hydrogen cooling. The cooling gas can be forced through

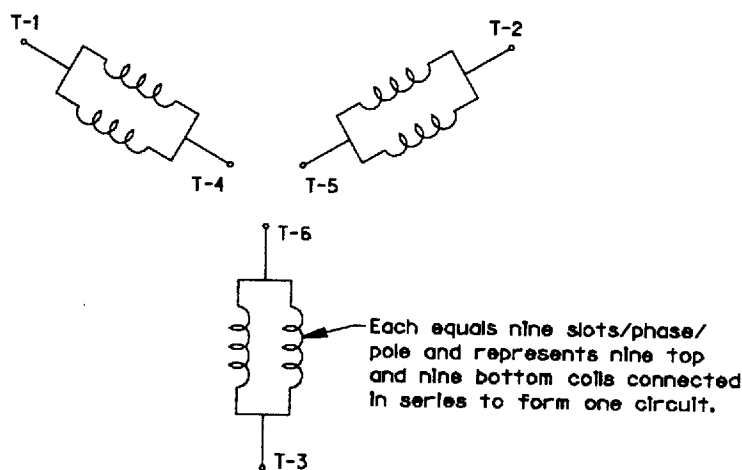


Figure 1-5 Typical Circuits for a 54-Slot, 2-Pole, Two-Circuit Generator Stator Winding

the hollow conductors through high- and low-pressure zones alternating down the axis of the machine (Figure 1-4); through alternating pickup and discharge slot wedges, also in zones down the machine axis; or through the use of hydrogen forced into the ends of the conductors in both end-winding regions and discharged radially through the middle of the rotor to the stator core. The rotor windings are connected to the excitation system via radial studs to half-moon-shaped copper conductors (bore copper) in the hollow bore of the rotor. They are then connected axially to radial studs outside the generator, which in turn connect to collector rings or to a brushless excitation system.

The rotor windings and forging are subjected to high stresses from rotational forces. The copper windings are therefore restrained by aluminum or steel slot wedges depending on the magnetic requirements. Retaining rings of high-strength steel are used over the rotor end windings to restrain them.

Circumferential or axial slots are cut in the pole faces of 2-pole rotors to try to equalize the stiffness in all directions and reduce vibration. These slots are normally called flexibility slots (Figure 1-6).

Journal or sleeve-type bearings support the rotor at each end and are supported by end bells or bearing brackets, or by separate pedestals external to the generator.

Bearing insulation is normally provided on the non-drive-end bearing to prevent shaft currents caused by shaft voltages resulting from magnetic dissymmetry in the generator; electrostatic charges from the flow of dry steam; ripple voltages from the solid-state excitation system conducted to the shaft via the field-winding capacitance; and magnetized shafts. The rotor shaft is normally grounded

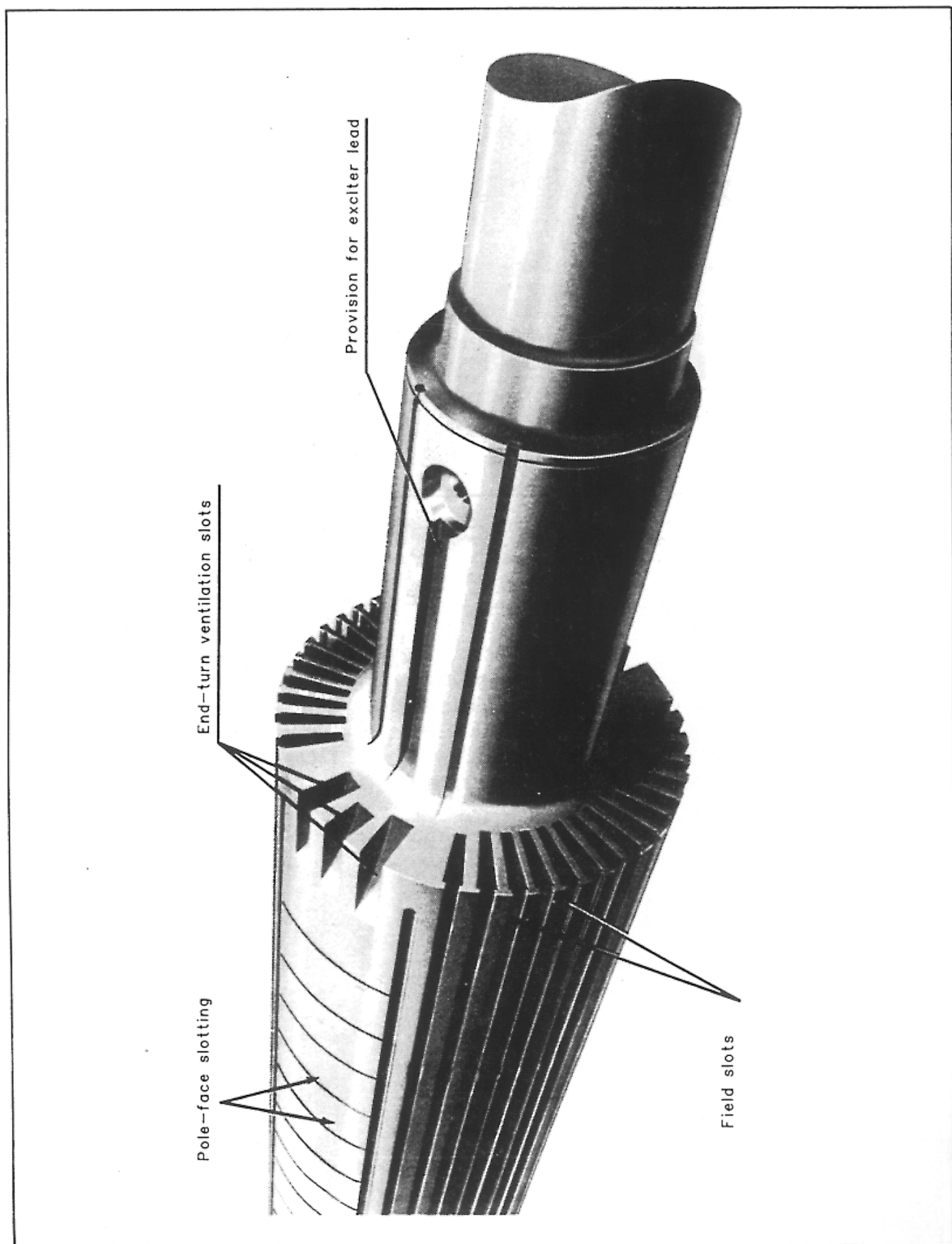
at only one location by silver brushes (in the turbine front standard), or copper braids or carbon brushes (at the drive end of the generator) that ride on the shaft. Carbon brushes are not as effective for shaft grounding as copper braids. The carbon-brush faces tend to become nonconducting. Frequent (almost daily) sanding of the brush faces is required for the carbon brush to make good contact with the shaft. When turbine steam seals are used, grounding is required to prevent shaft voltage buildup, which will arc to ground across clearance components such as bearings or gear drives and will damage the contact surfaces, causing failures. Older turbines with water seals are continuously grounded and do not require shaft-grounding devices. Shafts must be grounded at only one location to avoid shaft current flow among multiple shaft grounds.

Carbon brushes have been used for shaft grounding but require daily maintenance to preserve good contact with the shaft. The brush-to-shaft contact surfaces glaze over because of the small current flow involved and produce a high-resistance contact. Copper-braid grounding, on a shaft surface capable of withstanding the abrasion, is more effective.

COOLING

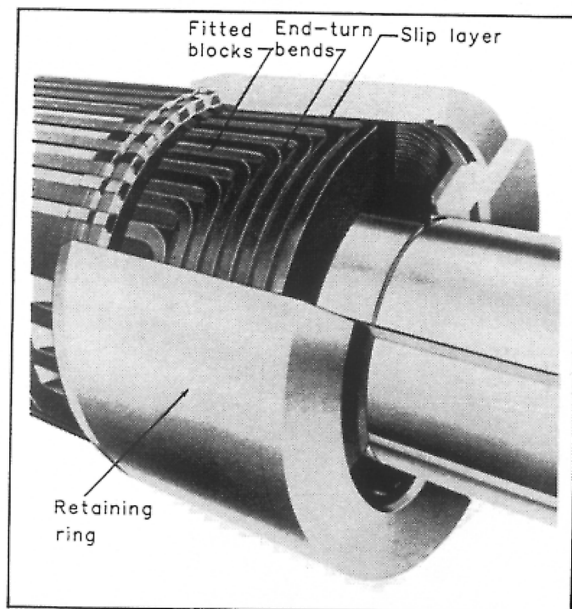
Cooling gases or liquids are required to extract the heat produced by generator losses such as core losses, stator and rotor winding I^2R losses, stray losses, and windage losses.

Synchronous machines can be cooled either indirectly or directly. Indirectly cooled armature or field windings are those in which the heat generated within the principal portions of the windings



SOURCE: R. W. Beckwith, *Westinghouse Power Systems Marketing Training Guide on Large Electrical Generators*, Pittsburgh, Pa.: Westinghouse Electric Corp., 1979, p. 46, Figure 21.

Figure 1-6 Machined Generator Shaft



SOURCE: R. W. Beckwith, *Westinghouse Power Systems Marketing Training Guide on Large Electrical Generators*, Pittsburgh, Pa.: Westinghouse Electric Corp., 1979, p. 48, Figure 22.

Figure 1-7 Rotor End Winding With Portion of Retaining Ring

must flow through the major groundwall insulation before reaching the cooling medium. Because all materials that are good electrical insulators are also good heat insulators, indirect cooling has definite limitations. Directly cooled armature or field windings are those in which the coolant flows in close contact with the conductors so that heat generated within the principal portions of the windings reaches the cooling medium without flowing through the major groundwall insulation. For historical reasons, indirectly cooled machines are sometimes called conventionally cooled; directly cooled machines are sometimes called conductor cooled or inner cooled.

Older indirectly cooled machines use air as a coolant. Fan blades and end shields direct air from under the machine into the air gap from each end. The air then passes through the radial ducts in the armature stack and finally out to the atmosphere from the top of the machine. Schemes for circulating air include radial, circumferential, and axial methods. Most new indirectly cooled machines use hydrogen rather than air as a cooling medium because hydrogen is lighter and therefore reduces windage losses. It also has a better heat transfer coefficient so that, for a given temperature differential between the winding and the

coolant, more heat is transferred from the winding to the coolant.

Air-cooled generators may use cooling air from the outside or from heat exchangers to extract generator heat. The heat exchangers may be external, with external fans to recirculate the air through the generator.

Hydrogen-cooled generators use hydrogen at 0.5- to 75-psig pressure in a gas-tight enclosure to cool the machine. The hydrogen is moved through the machine by fans or blowers. Heat is extracted from the hydrogen by means of hydrogen-to-water heat exchangers (coolers), which are mounted integrally in the generator. The coolers may be mounted vertically, axially, or transversely, depending on the design.

In an indirectly (conventionally) cooled generator, the heat from I^2R losses must flow across the groundwall insulation to the surrounding steel or wedges, then to the cooling gas (Figures 1-1 and 1-2).

Direct-hydrogen-cooled generators have the hydrogen flowing in direct contact with cooling tubes, which are in close contact with the stator windings along the machine axis. The rotor windings are cooled by direct contact of the hydrogen with the copper conductors (Figure 1-3).

Direct-water-cooled stators use highly purified (low-conductivity) water flowing through hollow copper conductors—or stainless steel cooling tubes—of the stator winding. Certain European manufacturers have built generator rotors with direct-water-cooled windings. Many steam turbine generators of recent design have direct-water-cooled stators and direct-hydrogen-cooled rotors (Figure 1-4).

A few generators have been built with direct-oil-cooled stators and direct-hydrogen-cooled rotors.

SUPERCONDUCTIVITY

The phenomenon of superconductivity was discovered in 1911 at the time scientists believed superconductivity occurred when materials were kept close to absolute zero, or -459.7°F . At this temperature, the resistivity of certain conductors practically drops to zero. Losses in the generator are minimized, and an efficiency near 99.5% can be accomplished, compared with 98.7% for conventional generators. Additionally, much smaller units can be used because of higher allowable current densities in the conductors.

A superconducting generator operates similarly to a conventional rotating electric generator.

Conductors in a rotor create a revolving magnetic field that produces a flow of electricity from conductors in a cylinder or stator that surrounds the rotor. However, in practice the superconducting generator differs appreciably from the conventional generator. Its rotor is cooled with liquid helium to maintain the conductors at nearly absolute zero. The superconducting generator is made of a non-magnetic material and has a hollow rotor through which liquid helium is supplied to the rotor's magnetic field winding.

Liquid helium is difficult to handle and is an expensive chemical. Researchers have accomplished superconductivity with warmer liquid nitrogen. Liquid nitrogen, which has a temperature of -321°F is much cheaper and 20 times more effective than liquid helium as a coolant. This technology is changing rapidly; superconductivity is being attained at higher and higher temperatures.

There are difficult engineering challenges in building a superconducting generator. The rotors have to be cryogenically cooled, and the very cold parts of the rotor must be well insulated to avoid excessive heat leakage. Vacuum insulation and carefully designed struts and current-carrying leads are required. Excessive energy losses due to centrifugally induced convection must be prevented.

EPRI has performed research on superconducting generators in conjunction with Westinghouse Electric Corporation. Manufacturing designs have been made for a medium-size generating unit. This unit may be built sometime in the future, when there is a greater need for new generating capacity.

AUXILIARY SYSTEMS

Auxiliary systems are required to provide the gases and liquids needed for cooling, sealing, and lubricating the generator.

Air-cooled machines may have external motor-driven fans to supply ambient air or air cooled by air-to-water heat exchangers. Some small air-cooled gas turbine generators take ambient air through filters into the machine.

Generators that use hydrogen for all or part of the cooling scheme employ hydrogen-to-water heat exchangers (coolers) mounted on or in the machine. An auxiliary system is used to maintain sufficient hydrogen pressures for safe operation and to supply makeup hydrogen to replace losses from leaks or purging. A low-hydrogen-pressure alarm is provided to alert the operator to unsafe operating conditions, such as the generation of

real or reactive power outside the generator capability curve (see Section 1.10); loss of hydrogen seal-oil pressure; massive hydrogen leaks; or hydrogen's approach to atmospheric pressure, which may permit air to enter the casing and produce an explosive mixture or overstress the generator fans or blower. Hydrogen purity devices will also alarm when the purity falls to 90%. This fact indicates that the machine must be purged with pure hydrogen to increase the purity; it may also indicate the existence of a source of contamination or the use of inadequate purging procedures when gassing the machine with hydrogen.

The hydrogen supply system normally includes the following:

- A bulk supply such as trailers, tubes, or cylinders
- Piping, relief valves, and pressure regulators to prevent exceeding the hydrogen-pressure limit of the generator
- A gas meter to monitor hydrogen consumption
- Valves, piping, and vent lines to permit gassing and degassing the machine

Carbon dioxide is normally used for the intermediate gas when changing from air to hydrogen or from hydrogen to air. Extreme care must be taken during these procedures to prevent an explosive mixture of hydrogen and air in the generator.

Certain manufacturers prescribe hydrogen dryers for their units to remove moisture, prevent corrosion, and avoid carrying corrosion products to the stator and rotor windings. Other manufacturers do not provide dryers because they believe that dry hydrogen provided by suppliers is adequate to keep moisture out of the machine and maintain an adequate dew point. The use of gas dryers is mostly a function of the design of the hydrogen seal-oil system. Those manufacturers that either vacuum treat the hydrogen-side oil or use a triple seal-oil system do not need to use gas dryers. Only those designs that allow free exchange of bearing oil and the hydrogen-side seal oil need hydrogen gas dryers; for these systems it is imperative that the hydrogen dryers be maintained in an operable condition.

A typical maximum dew point for machine hydrogen is 30°F , and monthly checks should be made to ensure that moisture is not entering the casing. Water from hydrogen coolers or stator water systems, from wet makeup hydrogen, or from

turbine steam leaks into the bearing lube oil may transfer to the hydrogen seal oil and migrate into the generator casing. It is critical that moisture be kept out of generators, both in service and out of service if austenitic steel (18% manganese-5% chromium alloy) retaining rings or zone rings are used. Moisture can cause corrosion (rust) on the rings and result in cracks or fractures. The use of 18-18 steel alloy rings has been shown to reduce the incidence of stress corrosion cracking.

The hydrogen seal-oil system provides lubricating and seal oil to the shaft seals. The number of seal rings per shaft end varies from one to three depending on the manufacturer. The seal-oil pressure is regulated to maintain a pressure level of 6 to 12 psig greater than the hydrogen pressure in the generator casing and thus to prevent blowing the seals. Upon loss of seal-oil pressure, hydrogen and oil mist will be blown into the turbine room; there is then a serious possibility of fire if an ignition source exists. Evaluations of fire-protection systems should account for this concern (see EPRI reports NP-2843 and NP-4144).

The seal-oil system includes ac- and dc-motor-driven pumps, piping, valves, pressure regulators, detaining tanks, reservoirs, and gages. Scavenging systems remove the hydrogen from the seal oil through arrangements of the tanks and drains. Vacuum degassing systems may provide a vacuum pump to extract hydrogen from the seal-oil storage tank.

Generators with direct-water-cooled stator windings have an auxiliary system to provide extremely low conductivity water that has also been cooled. The low-conductivity water of about 0.5 micromhos/cm is required to prevent conduction of electricity through the Teflon hoses that connect the stator bar water boxes to the circumferential water headers, normally an inlet at one end of the machine and an outlet header at the opposite end. The low conductivity is accomplished with deionizers that continuously polish about 10% of the total flow required to cool the stator.

The stator water systems include the deionizers, filters, coolers, pumps, stainless steel piping, strainers, regulators, alarms, and storage tank.

The stator water is cooled by the heat exchanger and normally has a pressure at the inlet to the stator bars that is less than the casing hydrogen pressure. For example, the casing pressure may be 60 psig and the stator inlet water pressure may be 22 psig. In the event of a stator-system leak inside the generators, the hydrogen will flow into the stator water system, where an alert operator

can quickly note the pronounced increase in stator water conductivity (perhaps 5 to 10 micromhos/cm). The hydrogen alone does not cause the increase, but it carries dust and contaminants into the stator water to cause the conductivity increase.

Stator water flow is critical to the safe operation of the generator. On loss of flow, the generator must either be run back to a no-flow capability or tripped off-line. Similarly, stator water temperatures are critical, and the water must not be allowed to boil, as boiling may cause thermal damage to the stator insulation. For example, if the stator winding outlet is at atmospheric pressure, the stator water must not be allowed to reach 100°C. Prudent operation requires tripping the unit when the stator water temperature reaches 85 or 90°C. The air or steam pockets in Teflon hoses are also of concern because they may result in a flashover between the bar conductor and ground.

Alarms are normally provided for deviations from safe stator flows, pressures, and temperatures. Numerous other alarms warn of high and low levels in the storage tank, plugged filters, high conductivity, and a tripped stator coolant pump.

The stator water system may also provide cooling water for the generator bushings and rectifiers for the excitation system. Some systems may have 100%-redundant pumps, coolers, filters, strainers, and deionizers so that failures of any one of these components will not curtail generator load.

The checklist on page 1-46 is useful for detecting trends or deviations from acceptable generator limits.

1.4 HYDRAULIC TURBINE GENERATORS AND GENERATOR/MOTORS

Hydraulic turbine generators, or hydrogenerators, produce alternating current and are driven by a hydraulic turbine or waterwheel.

Most of these machines are synchronous generators, and the discussion in this section applies to this type. Induction generators can also be driven by hydraulic turbines; this type of machine is described in Section 1.5.

A generator/motor may be used as either a generator or a motor, usually by changing rotational direction. The virgule between the terms indicates their equality and indicates that the machine serves one function or the other but not both at the same time. The word *generator* is

placed first to distinguish between this term and the commonly used term *motor-generator*, which has an entirely different meaning. A generator/motor has a particular application in a pumped-storage operation, in which water is pumped into a reservoir during off-peak periods and released to provide generation for peaking loads.

Generators are designed to optimize performance in the one direction of rotation. A generator/motor is a compromise in the designs of both the generator/motor and the waterwheel to accommodate both directions of rotation.

Generator ratings vary from about 300 kW to about 700 MW. Speeds vary from about 72 to 450 rpm, as determined by the waterwheel and hydraulic head. In general, the higher the head, the higher the waterwheel speed. At the very low head end, however, speed-increasing gears may be employed to permit the use of a higher-speed generator with a low-speed waterwheel.

Pelton or impulse hydraulic turbines are used for very high heads. Francis or reaction turbines are used for intermediate heads, while Kaplan or propeller turbines are used for low heads. There is an overlap of application between types of waterwheels, as shown in Figure 1-8.

Most of these machines are air cooled and use ambient air or air-to-water coolers. Certain recent extra-large generators have direct-water-cooled stator windings.

TYPES OF GENERATORS

This section discusses vertical, umbrella, horizontal, tube, and bulb generators. Each type includes the basic components of frame, stator core, stator windings, rotor shaft and spider, rotor poles and windings, exciters, bearings, and coolers.

A conventional vertical-shaft generator is shown in Figure 1-9. Note the combined upper-guide- and thrust-bearing assembly above the generator and one guide bearing beneath the generator.

Figure 1-10 shows an umbrella design, which also has a vertical shaft and a combined guide and thrust bearing beneath the generator. There are normally no bearings above. The umbrella name comes from the shape of the rotor, which resembles an opened umbrella.

Horizontal generators are used with some smaller reaction turbines and for many impulse turbines. Bearing-bracket construction is used for smaller machines, while pedestal bearings are used for larger ratings. Electrically, horizontal generators are similar to vertical machines. The

waterwheels may drive at a right angle or axially to the generator.

Tubular generators, which are on slant-axis shafts, were developed for tubular or axial-flow turbines and are applied for very low head (25 ft or less) plants. Tubular turbines reduce costs by simplifying the flow passages, eliminating the spiral case, and reducing the size of the civil structure. A typical tubular turbine design may use a rim generator, in which the generator rotor is attached directly to the periphery of the fixed propeller blades and recessed into the conduit wall. A modification of this design might include a tubular turbine driving an externally located generator through a long shaft and a speed-increasing gear.

Bulb generators are encased in a bulb or watertight enclosure in the middle of a flow conduit and driven by an axial-flow turbine. Smaller-capacity units may use speed-increasing gears. Bulb units are very compact but require a sophisticated design to fit the generator into a bulb of acceptable size. The design must provide for machine heat losses to be transferred by air to the bulb case and then to the water surrounding the case. In some large units the generator enclosure is accessible, but in smaller units no access is provided, and the plant must be dewatered to service the generator.

STATOR CONSTRUCTION

Stators consist of the frame, which supports all the generator components; the core, which provides the magnetic flux paths; and the stator windings. Most hydraulic turbine generators and generator/motors are vertical machines. Their components are described below.

The stator frame is normally made of welded steel plate and is machined in the factory. Stator punchings or core laminations of approximately 0.014-in. silicon steel are stacked vertically on dovetails supported by the frame. The insulated punchings are segmented and contain slots for the stator windings. Heavier punchings of about 0.025 in. are used every 2 in. to support vent spacers, which provide openings for cooling airflow through the core. Core heights vary from 12 to 60 in. or more. Core inside diameters may be as small as 3 ft or as much as 40 ft or more. Very large machines are built in sections in the factory and then dismantled to provide a component size suitable for shipping. In some cases the frame may be built in a factory and shipped in sections to the plant site for stacking of the core iron and installation of the stator windings.

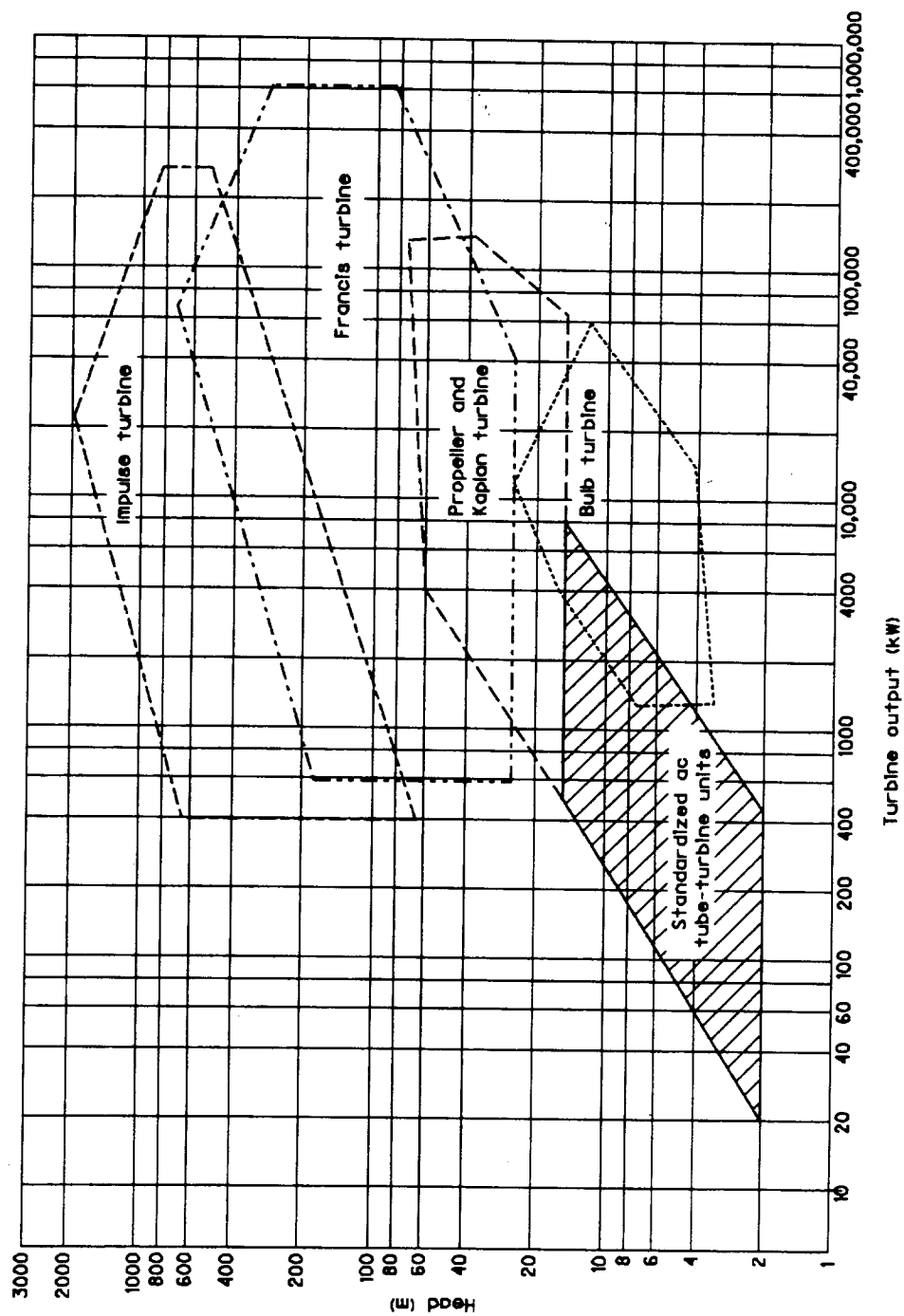
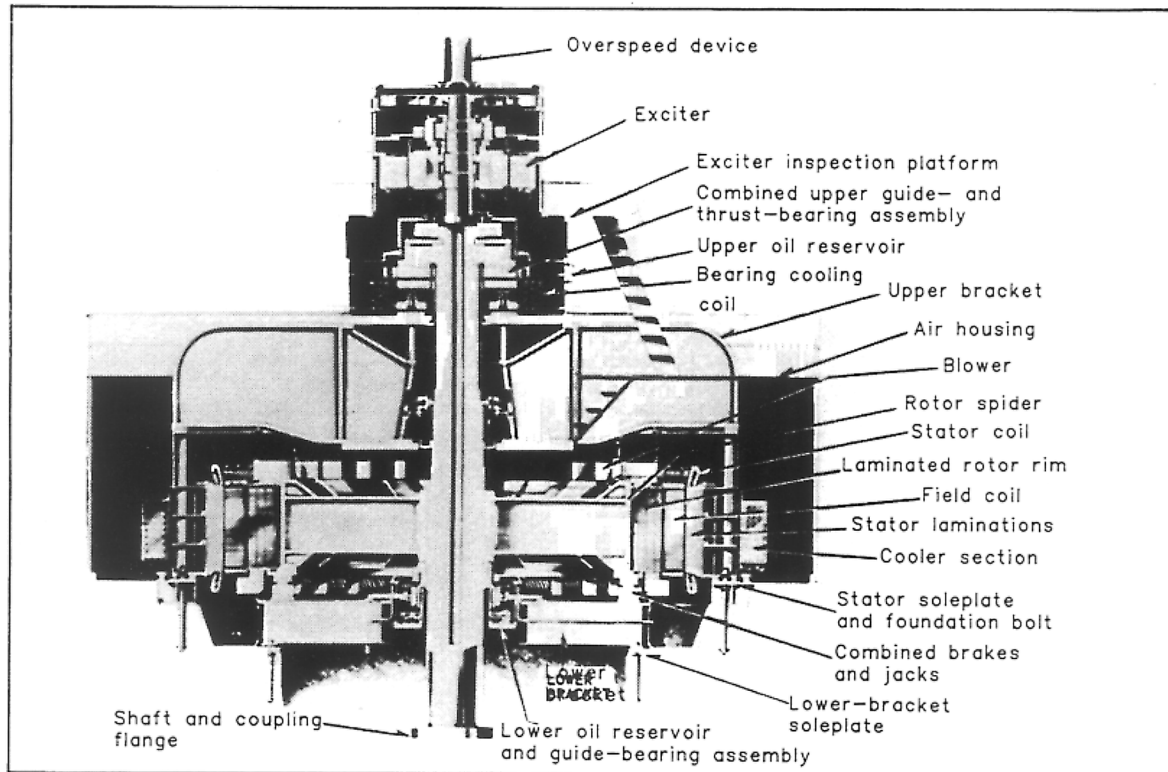


Figure 1-8 Common Application Ranges for Conventional Hydraulic Turbines



SOURCE: R. W. Beckwith, *Westinghouse Power Systems Marketing Training Guide on Large Electrical Generators*. Pittsburgh, Pa.: Westinghouse Electric Corp., 1979, p. 110, Figure 44.

Figure 1-9 Cross-sectional View of Conventional Two-Guide Bearing Generator

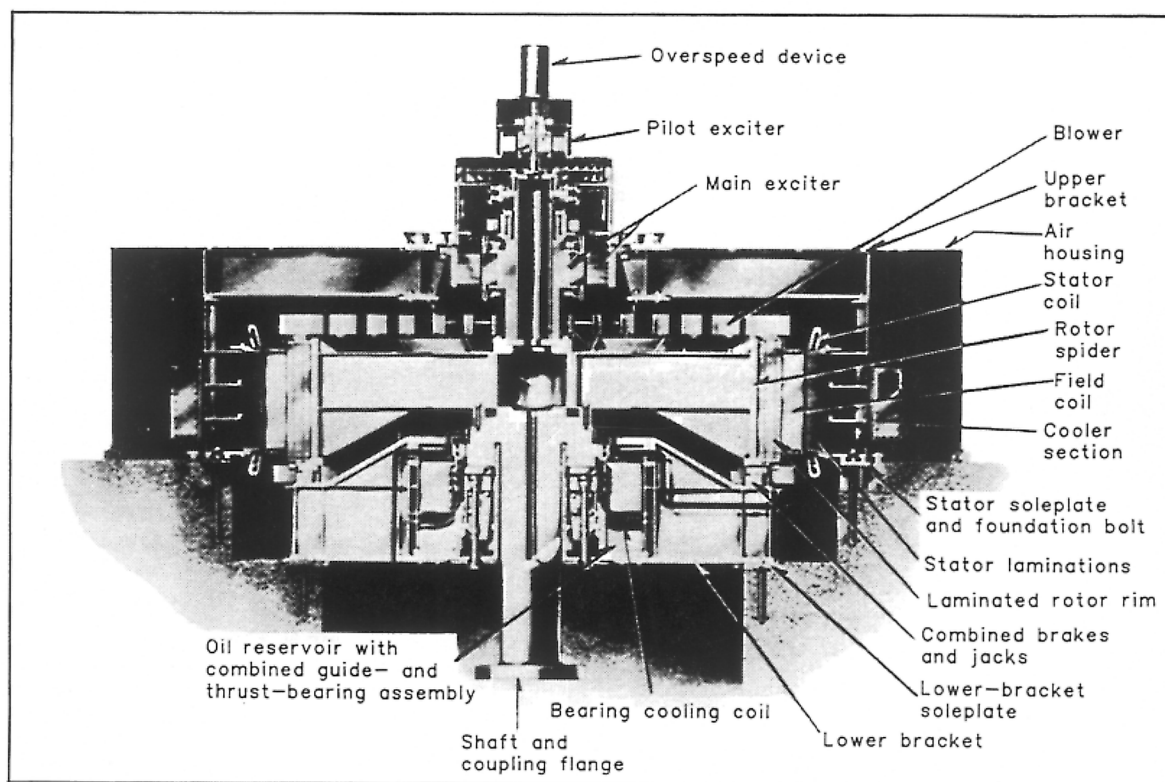
The stator windings may be formed from multiturn lap coils. In recent years, some large machines have been wound with bar-type, single-turn coils similar to bars used in steam turbine generators. The number of slots and coils in a hydro machine ranges from 100 to 600.

The coils are formed from copper strands, each insulated with materials such as fiberglass, Dacron-glass, various types of films, and in some cases an added resin or varnish. The stranded construction minimizes losses from eddy currents. Multiturn coils will also have insulation, such as glass-backed mica tape, between turns. The coils are then insulated from ground with multiple layers of mica tape; the number of layers depends on the stator voltage.

Hydro machines built up to the early 1960s were most likely to use asphalt or bitumen varnishes with the mica tapes. Many of these machines are still in service and operating satisfactorily. Many have failed because of overheating (generally caused by turn-to-turn short circuits), internal

voids and consequent damage from partial discharge, and groundwall failures.

Many older machines have been rewound with coils that still use mica tapes but with the newer synthetic resins—epoxy or polyester—for impregnants in place of asphalt materials. Practically all new machines use the synthetic resins. While these newer coils are void-free—mostly as a result of vacuum-pressure impregnation (VPI)—the coils are much harder than asphalt coils and are much more difficult to keep tight in the slots. As a result, there have been numerous cases of synthetic bars coming loose—with consequent fretting, slot discharge, and erosion of the armor tape and groundwall. Periodic maintenance is required (perhaps every five years) to reestablish the coils' electrical contact with the core and to tighten the coils in the slots by the addition of side fillers and tight rewedging. Methods of monitoring partial discharges have been developed. These methods include capacitive couplers around the machine periphery and detection and analysis of high



SOURCE: R. W. Beckwith, *Westinghouse Power Systems Marketing Training Guide on Large Electrical Generators*. Pittsburgh, Pa.: Westinghouse Electric Corp., 1979, p. 110, Figure 45.

Figure 1-10 Cross-sectional View of Umbrella Generator

frequencies caused by partial discharges from the generator connections.

The coils are connected in series and parallel rings (or circuit rings) run along in combinations, as appropriate for the voltage level, to form the windings. Parallel or ring circuits run along the periphery of the stator to bring the winding connections out to the line and neutral bushings or terminations.

ROTOR CONSTRUCTION

Hydraulic turbines run at speeds slower than 1800 rpm. The generator for a hydraulic turbine running at 100 rpm has 72 poles, and for such a machine a forged rotor with milled slots would be impractical and unnecessary. For low-speed machines, the poles are fabricated separately; the windings are installed and the whole assembly bolted or keyed to a pole spider. The spider is often like a spoked wheel with the shaft through the hub. Rotors constructed in this manner are known as salient-pole generators.

The rotor shaft is machined from a steel forging and has a half-coupling for bolting to the water-wheel. The spider is mounted on the shaft via a sleeve and keys and, in some cases, via bolts. The spider consists of the sleeve with radial H-beam arms welded to it. For small machines a rolled steel rim is mounted circumferentially at the outer periphery of the spider arms. Larger machines have laminated-sheet-steel rims. Field poles are built from laminations and stranded or edge-wound copper turns, insulated from each other and from ground and mounted on the rotor rim with either bolts or keys driven into dovetails on the poles. The pole faces normally have damper bars (amortisseur windings), which are short-circuited at both ends of each pole. The end connections may then be connected circumferentially to all other poles to form a continuous amortisseur winding.

The windings on each field pole are then connected in series to form the field winding, and leads are brought out via a spider arm to the shaft

and then run axially to collector rings. Excitation is supplied to the collector rings from shaft-mounted exciters, separate motor-driven exciters, or a solid-state excitation system. See Figures 1-9 and 1-10 for sectional views of the rotor, salient poles, and exciters.

COOLING

Most hydraulic turbine generators and generator/motors are air cooled. Smaller machines may be cooled with ambient air, which is forced through the stator core, around the stator end windings, and around the rotor poles—either by fans mounted on the rotor or by the pumping action of the rotor poles themselves.

Larger machines have air-to-water heat exchangers mounted on the outside casing of the stator frame. Fans or blowers can be mounted on the top or bottom (or both) of the rotor to move air over the rotor poles and stator windings and through the core.

AUXILIARY SYSTEMS

One auxiliary system associated with the generator provides the water to supply the air-to-water heat exchangers. This system consists of pumps, valves, regulators, and piping. Temperature detectors to check the air in and out from the coolers may be used to indicate when the cooler tubes need cleaning or have an air lock in the waterside.

Hydro machines with direct-water-cooled stator windings have a stator water system similar to that described in Section 1.3 of this volume. Another auxiliary system provides oil to the bearings and is normally part of the lubricating-oil system for both the waterwheel and generator bearings. The thrust bearings on vertical machines are usually submerged in oil and are self-lubricating. Yet another (high-pressure) oil system may be provided to lift the rotor and separate the thrust-bearing shoes and runner for startup. The high-pressure oil system will also come on during shutdown when the generator reaches 25% to 30% speed; it remains on until the generator stops rotating.

BRAKING SYSTEM

High-pressure air is normally used in the braking system of hydro machines. Brake pads are spaced circumferentially around the bottom of the generator and are applied to a brake ring on the rotor.

Speed switches on the generator trigger brake operation at a preset low speed. After load has been removed from the generator and the generator has been disconnected from the system, the machine is allowed to decelerate to 20% to 50% speed. The brakes are then applied intermittently or continuously until the rotor reaches 10% speed, then continuously until the rotor comes to rest. One purpose of the braking system is to stop the machine rapidly and avoid damage to the thrust bearing by a loss of oil film at very low speeds.

STARTING METHODS FOR PUMPED-HYDRO UNITS

In the pumping mode, the generator/motor functions as a motor. It rotates in the direction opposite that of the generation condition. Therefore, a method must be used to start the motor before water is admitted to the turbine and pumping begins.

Three major categories of methods to start generator/motors have evolved since the concept of pumped hydro was developed in Switzerland in 1879 and first applied in the United States in 1927. These categories are asynchronous starting with a cage or solid-damper winding in the generator/motor rotor; asynchronous starting with a pony-motor mounted on the shaft end; and back-to-back starting, also called synchronous starting at variable frequency. IEEE Standard 492-1974, *Guide for Operation and Maintenance of Hydro-Generators* (1) has additional information on these three starting methods. Note that certain plants with multiple units may use various combinations of these starting methods. Note also that the water in the waterwheel cavity is generally depressed by the use of compressed air during the starting period for any of these methods. The asynchronous method using a cage or solid-damper winding can be broken down to variations described below. Phase-reversing switchgear is required for the first three methods.

- Full-voltage induction start, in which the generator/motor has a heavy continuous amortisseur winding on the rotor poles, which starts the unit as an induction motor across the line.
- Reduced-voltage induction start, in which the unit is started as an induction motor at reduced voltages supplied either from taps on the unit transformer, an autotransformer,

or reactors in the leads, or from a delta-wye shift of the unit transformer connections.

- Reduced-voltage, reduced-frequency start, in which the machine is started from rest after being electrically connected to a decelerating generator of comparable size. The energy of the rotating deceleration generator is electrically transferred to the generator/motor with reduced voltage and frequency. The units are synchronized at subsynchronous speed, accelerated to rated speed with the generator turbine, and synchronized to the system in the normal manner. In a variation of this method, the generator and motor both start from rest; this method would be considered a synchronous start.
- Variable-frequency, reduced-voltage start, in which the generator/motor is started from a static variable-frequency source capable of supplying starting power from zero frequency to greater than 60 Hz and at a value of reduced voltage suitable to the application.

Asynchronous pony-motor starting consists of a wound-rotor induction starting motor—large enough to overcome the losses of the generator/motor and accelerate it to synchronous speed—mounted on the shaft of the main unit.

Synchronous (back-to-back) starting can be broken down to the variations shown below, all operating one machine as a generator in parallel with a second machine acting as a motor:

1. Both machines paralleled at standstill and separated from the power system, with their field windings energized. Draft tube water is depressed below the turbine on the motoring unit. The machines are brought up to speed, one acting as a generator and the other as a motor. They are synchronized to the system, and the generating machine is shut down. Water is then admitted to the motoring unit for pumping.
2. The same as variation 1 except that the motor unit does not have its field energized and therefore acts as an induction motor during starting. The field is applied after the motor is near synchronous speed.
3. Similar to both variations 1 and 2, but the generator is driven by a smaller, nonreversible accessory-type turbine.

4. Similar to variations 1 and 2, but the units are not paralleled until after the generator unit reaches some intermediate speed.

One other starting method is to use a small turbine mounted on the shaft of the main unit, with rotation opposite to that of the main turbine, to accelerate the motor pump to synchronous speed.

Another starting method, which is seldom used, employs an oversized shaft-mounted exciter for a dc-motor drive. A separate large motor-generator set is used to drive the exciter, with the pump motor excitation requirements supplied by an alternate source during starting. The low rating of the exciter leads to long starting times, normally in the range of 20 min.

1.5 INDUCTION GENERATORS

Induction generators are constructed like squirrel-cage induction motors. Induction motors can operate as induction generators when driven above synchronous speed. Prime movers for induction generators include steam, gas, hydraulic, expander, and wind turbines; diesel, natural gas, and gasoline engines; and centrifugal pumps.

Ratings vary from 3 kW to about 15 MW, with the larger sizes normally associated with hydraulic turbine drives. Voltage ratings vary from 200 to 6600 V or more.

STATOR CONSTRUCTION

The stator consists of a frame to enclose the generator and to support the core, windings, and bearings. The frame is machined from fabricated or cast steel components or combinations of each. Core punchings or laminations of about 0.014-in. silicon steel are stacked on ribs in the frame. The laminations are insulated with oxide, varnish, or a chemical treatment of the steel. The laminations are notched to accept the stator windings and provide the dovetails for wedges to secure the stator coils. After stacking, the laminations are tightly clamped with fingers and flanges at each end of the core.

The stator windings are normally formed from multiturn lap coils. The coils consist of copper strands insulated with fiberglass or with a mica-ceous system. The strands are formed into turns containing several strands (wires-in-hand) and

looped to form the coil; these coils are then spread into lap-type coils. Groundwall insulation is then applied to the formed coils. Groundwall insulation may contain tapes and wrappers of fiberglass, Dacron, mica, and films in various combinations and layers depending on the voltage rating. An armor tape may be applied over the outside for mechanical protection during winding. Various varnishes and resins are used to fill the coil; these fillings may be introduced from preloaded tapes by painting between layers, by dipping, or by vacuum-pressure impregnation. The VPI process can also be applied to the coil before insertion into the stator (hard coil) or after insertion into the stator (green coil). Generators rated 6600 V or higher will have conducting paint applied to the slot portions of the coils and may have grading paints starting near the core edges and proceeding out into the end windings. The coils are then connected in various series and parallel arrangements to form circuits and windings. Three-phase windings may have internal connections made to form a wye or delta and have only three leads brought out. Windings for larger generators may have six or more leads brought out to complete the three-phase circuits externally, thereby permitting the use of relaying and grounding schemes. Volume 8, *Station Protection*, provides more detail.

ROTOR CONSTRUCTION

The rotor is constructed from a steel shaft with machined journals for bearings, seal surfaces to confine the lubricating oil, and a support for the rotor core and rotor windings. The core laminations may be stacked and keyed directly to the shaft; stacked on a sleeve, which is shrunk or keyed to the shaft; or stacked on the ends of spider arms, which are welded directly to the shaft or to the aforementioned sleeve. A rim at the outer circumference of the spider arms may be provided to support the rotor-core laminations.

The rotor windings are of squirrel-cage construction. Rotor bars are inserted axially into the rotor laminations, which are punched with a semi-closed slot for the bars before stacking. Each bar is electrically connected at each end to the end rings, or short-circuiting rings, by brazing or welding to form the squirrel-cage windings. Rotor bars and end rings are made from copper, copper alloys, or aluminum. Cast aluminum rotors may be used for small induction generators. In recent years, fabricated (welded) aluminum rotors have

been developed. Rotor bar shapes include rectangular, T-shape, trapezoidal, round, and teardrop (a round bar with a fin at the outside diameter) designs. Symmetrical teardrop bars are not normally used because they tend to come loose from the laminations in time. Depending on the generator speed and rotor diameter, the end rings may require steel wire banding or retaining rings to withstand the centrifugal forces involved. Some manufacturers also use glass banding for support and noise suppression at the end rings.

Volume 6, *Motors*, provides more detail about induction motors, which are very similar to induction generators.

EXCITATION

Excitation is provided by the stator current in an induction generator because of the squirrel-cage rotor construction. The induction generator draws lagging volt-amperes-reactive from the system to provide the excitation. Depending on the application, the lagging volt-amperes-reactive can be obtained from synchronous generators in the system, shunt capacitors, line-charging capacitance, cable-charging capacitance, or static volt-ampere-reactive sources with thyristor control.

EPRI report EL-2043, *Application of Induction Generators in Power Systems* (2), describes significant points to consider, including excitation requirements, in applying these machines. Precautions are required for the use and switching of capacitance for power factor correction because of the possibility of shaft damage caused by shaft torsional forces.

1.6 ENGINE-DRIVEN GENERATORS

Engine-driven generators are synchronous, generally of salient-pole design, and have normal design speeds from 720 to 1800 rpm. Exceptions are small generators with a rotating armature and stationary field, those with a design speed of 3600 rpm, and special diesel engine-driven generators designed for 450 or 514 rpm.

Physically, a compact design is both feasible and desirable for the salient-pole ratings involved, so that the core diameter is usually roughly equivalent to the core length. Centrifugal force on the field poles is minimized, permitting speeds of 1800 and 1200 rpm (4 and 6 poles).

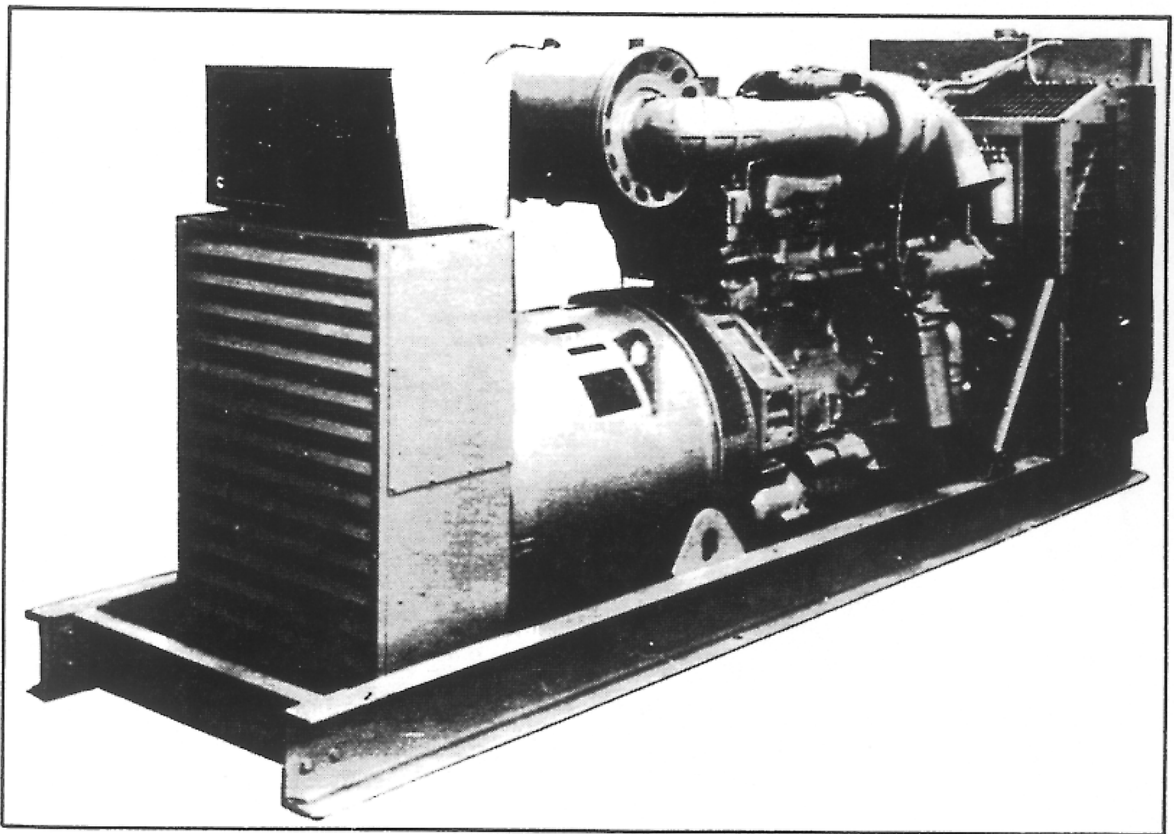
In the smallest generator designs, the armature is the rotating member and the current (often single phase) is brought out through slip rings. Stationary fields can be excited from a dc source, such as a silicon rectifier.

Excitation for salient-pole designs, described in Section 1.7, can be supplied from rotating dc exciters or static exciters using silicon diodes or thyristors (silicon-controlled rectifiers). Collector rings and brushes may be used to conduct the dc to the rotating field. Brushless exciters may also be used in which the exciter ac generator and rectifiers are mounted on the main shaft. Exciter output is controlled by adjusting the dc excitation of the exciter stationary fields. The output of the rotating exciter ac generator is rectified and fed directly into the field of the main machine without traveling through carbon brushes. Section 1.7 gives more details about excitation and voltage regulators.

Engine generator ratings vary from 500 W (single phase) to 7.5 MW. Voltage ratings vary from 120 to 4160 V for most applications. Various prime movers include gasoline, natural gas, or liquid petroleum gas engines for ratings of 500 W to 50 kW; diesel or dual-fuel diesel/natural gas engines for ratings from 50 kW to about 3 MW; reciprocating natural gas/liquid petroleum gas engines for ratings from 50 to 1300 kW; and gas turbines for ratings from 200 kW to 7.5 MW (at 13 kV).

Engine generators are often used as part of a packaged generator, which also includes the exciter and voltage regulator. A packaged generator set adds the prime mover, starting apparatus, and basic control devices to the packaged generator (3). Figure 1-11 shows a typical packaged generator set.

Standby power is frequently supplied from packaged generator sets. Standby power may include emergency power for hospitals and life support



SOURCE: "Electric Generators: Packaged Generator Sets." *Power*, March 1966, pp. S18-19.

Figure 1-11 Typical Diesel Packaged Generator Set

systems, lighting, elevators, heating, fire pumps, security and communication systems, uninterruptible power systems, critical process motors or machinery, controls, and essential air conditioning and refrigeration.

1.7 EXCITATION SYSTEMS

Excitation systems provide the source of field current for the excitation of a principal electric machine, including means for its control. The purpose of the excitation system is to furnish direct current to the rotating field of the electric machine and thereby induce voltages in the stator of the machine. Manual or automatic regulation of the direct current and direct voltage applied to the rotating field will regulate the output voltages of the principal machine. Variations in output voltages are required to meet system requirements for stability and reactive (volt-amperes-reactive).

Excitation systems have evolved from dc generators, driven off the main generator shaft or by an ac motor or even by a small waterwheel, to the present solid-state systems that use noncontrolled rectifiers (diodes) or controlled rectifiers (SCRs or thyristors). The solid-state system may be brushless, meaning that the ac power source and rectifiers all rotate on the end of the main generator and feed directly to the main generator field winding without going through brushes and collector rings. Other solid-state systems may have a shaft-driven alternator, a transformer, or separate generator windings and a transformer inside the main generator housing for an ac power source, which then supplies noncontrolled or controlled rectifiers connected to brushes and collector rings on the main generator rotor.

Voltage regulators have changed from early manual control of a rheostat in the shunt field circuit of a dc generator to the present static or solid-state automatic voltage regulators. Intervening systems included carbon pile, starwheel, amplidyne, magnetic amplifier, and other varieties of regulators. Voltage regulators control the output voltage of the generator. Field voltage to the generator is controlled by feedback from the generator voltage and current transformers to the automatic or dc (manual) voltage regulators where generator voltage levels are set. The voltage regulators control either the fields of dc exciters or alternators, or the input to controlled rectifiers; the controlled

rectifiers, in turn, determine the input to the generator field, thereby closing the loop.

IEEE Standard 421-1986, *Standard Criteria and Definitions for Excitation Systems for Synchronous Machines* (4), contains a comprehensive description of excitation systems, including voltage regulators, along with definitions of terms.

Excitation systems include a field breaker, an exciter field breaker, or an excitation breaker to apply and remove excitation for the field of the principal machine. Volume 8, *Station Protection*, describes loss-of-field protection and tripping of the field breaker to minimize damage during an electrical fault associated with the principal machine or related transformers. Certain excitation systems may include de-excitation circuitry to force reduction of the field flux and to reduce the energy fed to an electrical fault.

DC GENERATORS

Dc generators for exciters may have voltage ratings of 125, 250, 375, or 500 V. The kilowatt ratings may be as little as 5 kW for a pilot exciter to a 600-kW, 500-V exciter for a 239-MW 4-pole generator.

These dc generators are normally shunt wound. They may have a series field winding for voltage control and commutating and compensating windings for commutation control and prevention of brush sparking. Voltage control—and thus control of field current to the main generator rotor winding—is accomplished by the use of a rheostat in the shunt field circuit; voltage regulation is accomplished by the use of amplidynes or magnetic amplifiers, also in series with the shunt field winding. A schematic of a typical dc exciter supplying a main generator rotor winding is shown in Figure 1-12.

Many dc generators are direct-drive from the generator shaft and therefore turn at the same speed. At 1800 rpm and lower speeds, dc generators generally operate satisfactorily. At 3600 rpm, however, operation is often marginal because of commutator runout, brush vibration, and sparking. These 3600-rpm exciters were built in the early 1950s, but the design was later abandoned in favor of reduction-gear drives. Some 1800-rpm generators are also equipped with reduction-gear exciter drives.

Dc generators for exciters may be driven by an ac induction motor. These motor-generator sets may be used for reserve excitation to keep the

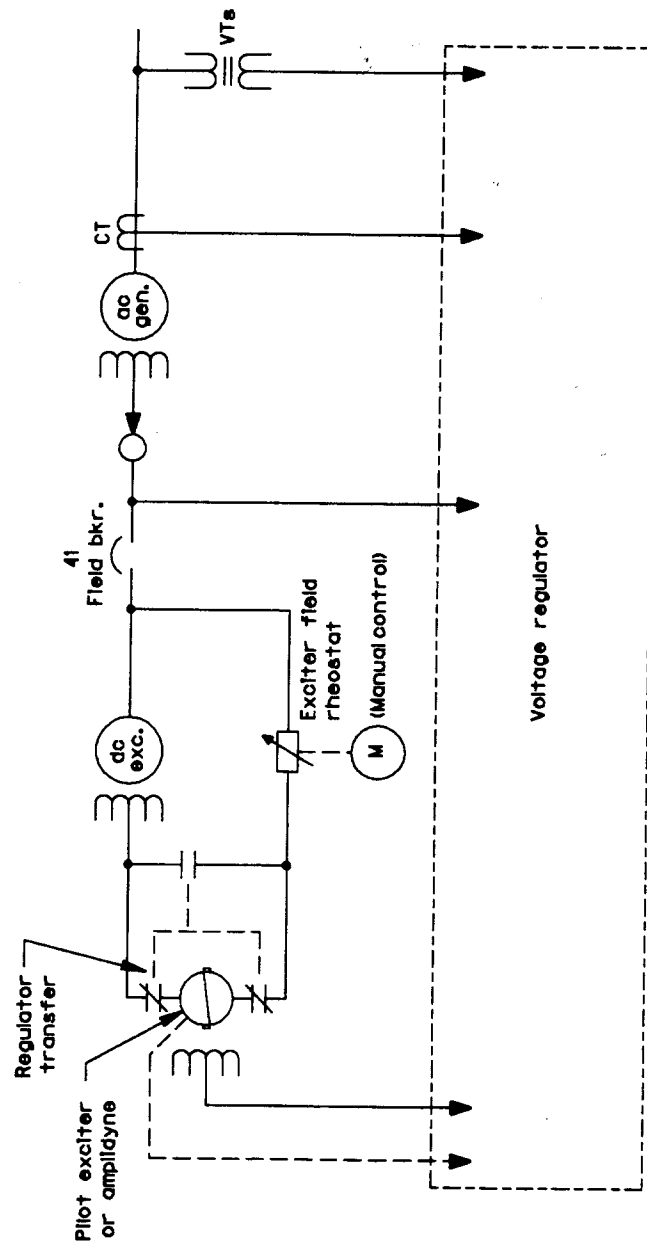


Figure 1-12 Typical DC Exciter Supplying a Main-Generator Rotor Winding

main generator on-line when a shaft-driven exciter is out because of a failure or operating problem. Reserve exciters may supply excitation to both main-generator rotor windings of cross-compound units during startup, when the turbine generators are rolled off turning gear. Operators may call this process compounding the generators.

Although dc generators have proven reliable historically, the carbon brushes and commutators require constant attention. A walk-by inspection is needed each shift, and a thorough check for sparking, short brushes, overheating of brush shunts, and freedom of the brushes to move within the brush boxes must be made at least weekly, or more often if the exciter is subject to operating problems.

ALTERNATOR

The alternator is a separate ac generator that is driven from the main turbine generator. The alternator may be a 4-pole ac generator that will supply 120 Hz to the excitation system when driven at 3600 rpm. The alternator rotating field is supplied from a solid-state source, which in turn may be supplied from a permanent magnet generator or from a critical horsepower circuit. The alternator field has collector rings and carbon brushes similar to the main-generator field circuit.

The ac output of the alternator is supplied to noncontrolled rectifiers (diodes) or controlled rectifiers (SCRs or thyristors) for rectification to direct current, which is then supplied to the main-generator field. A typical circuit arrangement is shown in Figure 1-13.

POTENTIAL SOURCE

Potential-source excitation systems are similar to alternator-supplied systems except for the power source. The ac power is supplied from a transformer (rather than an alternator), which is usually connected to the generator bus, as shown in Figure 1-14. In a variation, the transformer is connected to an auxiliary bus.

A current practice using the potential-source scheme is to install separate additional windings in the main-generator stator. These separate windings supply a transformer inside the generator housing. Low-voltage windings from this transformer come out of the generator housing to rectifiers; then the direct current is supplied to the main-generator rotor.

BRUSHLESS EXCITATION SYSTEMS

Brushless excitation systems were developed in the 1960s to eliminate dc generators and collector rings and their associated carbon-brush problems. The brushless system consists of a rotating alternator (with a stationary field) that is connected to rotating fuses and diodes. The output of the diodes is connected directly to the rotating main-generator field. Voltage control of the main-generator stator is via control of the stationary field for the alternator.

Brushless excitation systems may be air cooled in a housing separate from the main generator. A few of these systems are hydrogen cooled, taking cooled hydrogen from the main generator and returning the warmed hydrogen to the main-generator coolers.

A schematic for a typical brushless excitation system is shown in Figure 1-15.

1.8 BEARINGS

The types of bearings used for generators are determined by mechanical considerations of size, weight, and speed. Small machines may use antifriction bearings (ball or roller bearings). Larger generators may have journal (sleeve) bearings of bronze or babbitted steel shells. The largest generators normally use babbitted journal bearings for horizontal machines and guide bearings for vertical hydro generators. Thrust loads can be handled in the following ways:

- By thrust bearings in the prime mover
- By antifriction bearings designed to accept thrust loads
- By thrust collars incorporated with journal bearings
- By segmented, babbitted shoes that are supported by pivots or springs

Lubricants, whether oil or grease, must be suitable for all bearing applications and should be in accordance with the manufacturers' recommendations.

TURBINE GENERATORS

Journal or sleeve-type bearings support the rotor at each end and are supported by end bells or bearing brackets, or by separate pedestals external

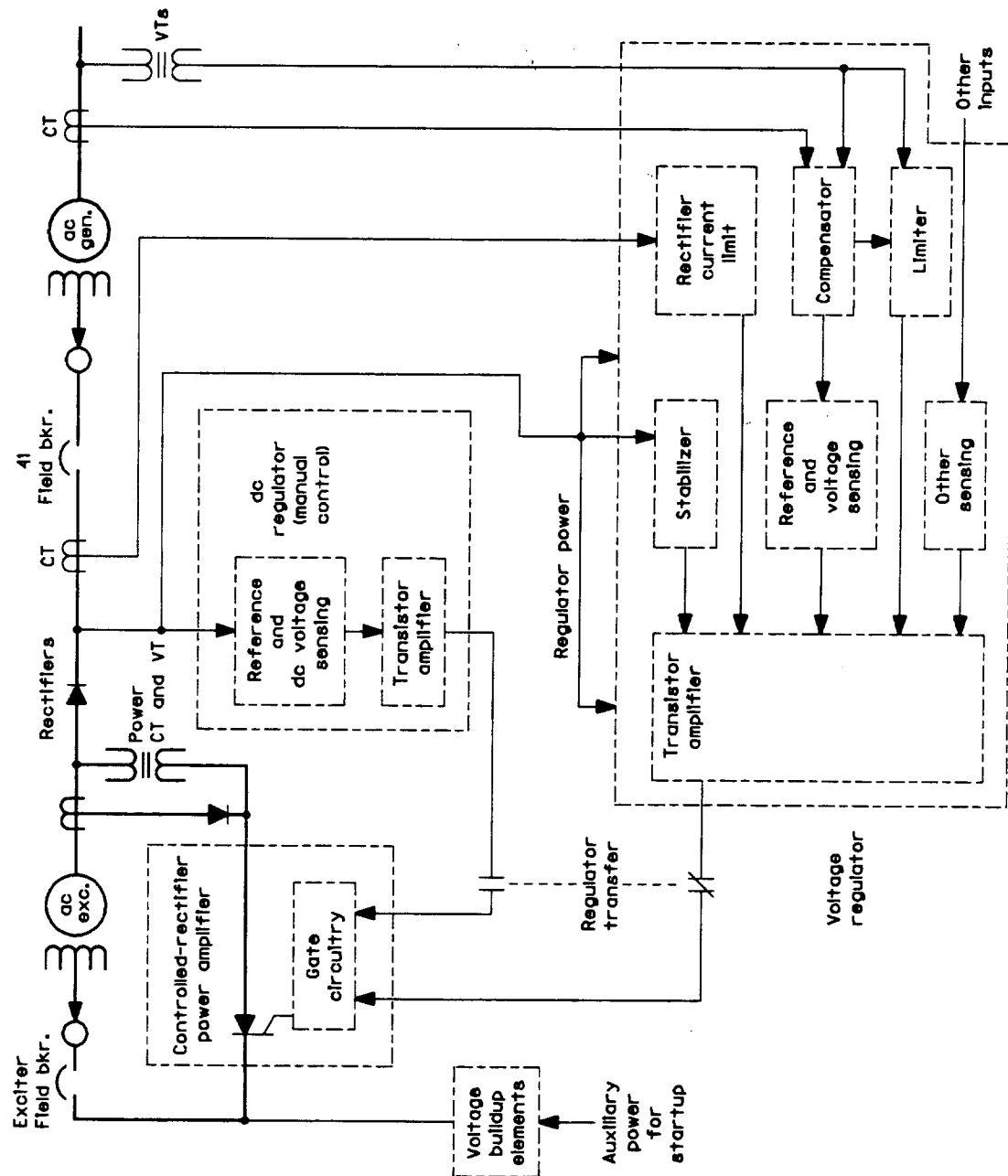


Figure 1-13 Excitation Control System With Alternator-Rectifier Exciter Using Stationary Noncontrolled Rectifiers

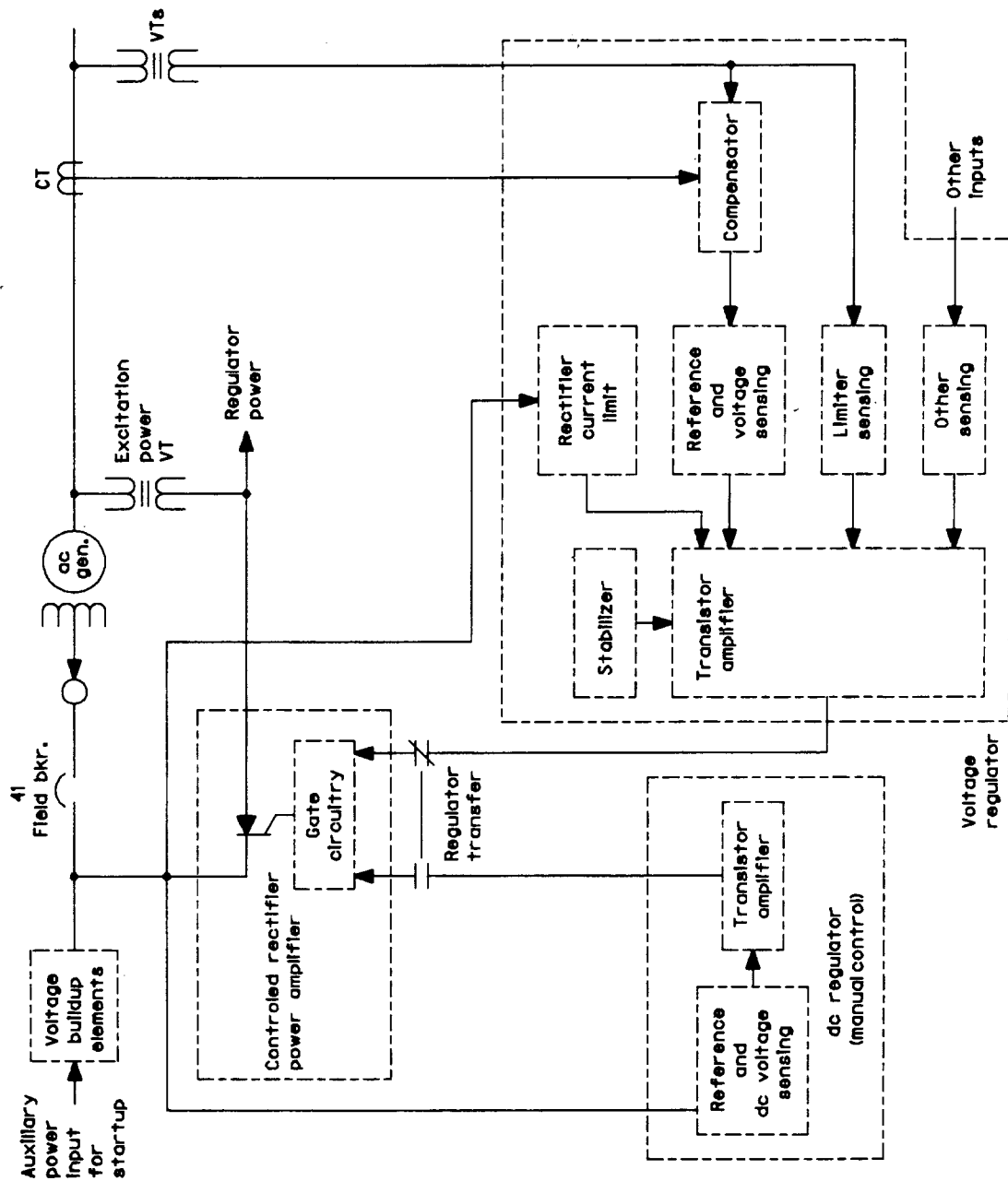


Figure 1-14 Excitation Control System With Potential-Source-Rectifier Exciter

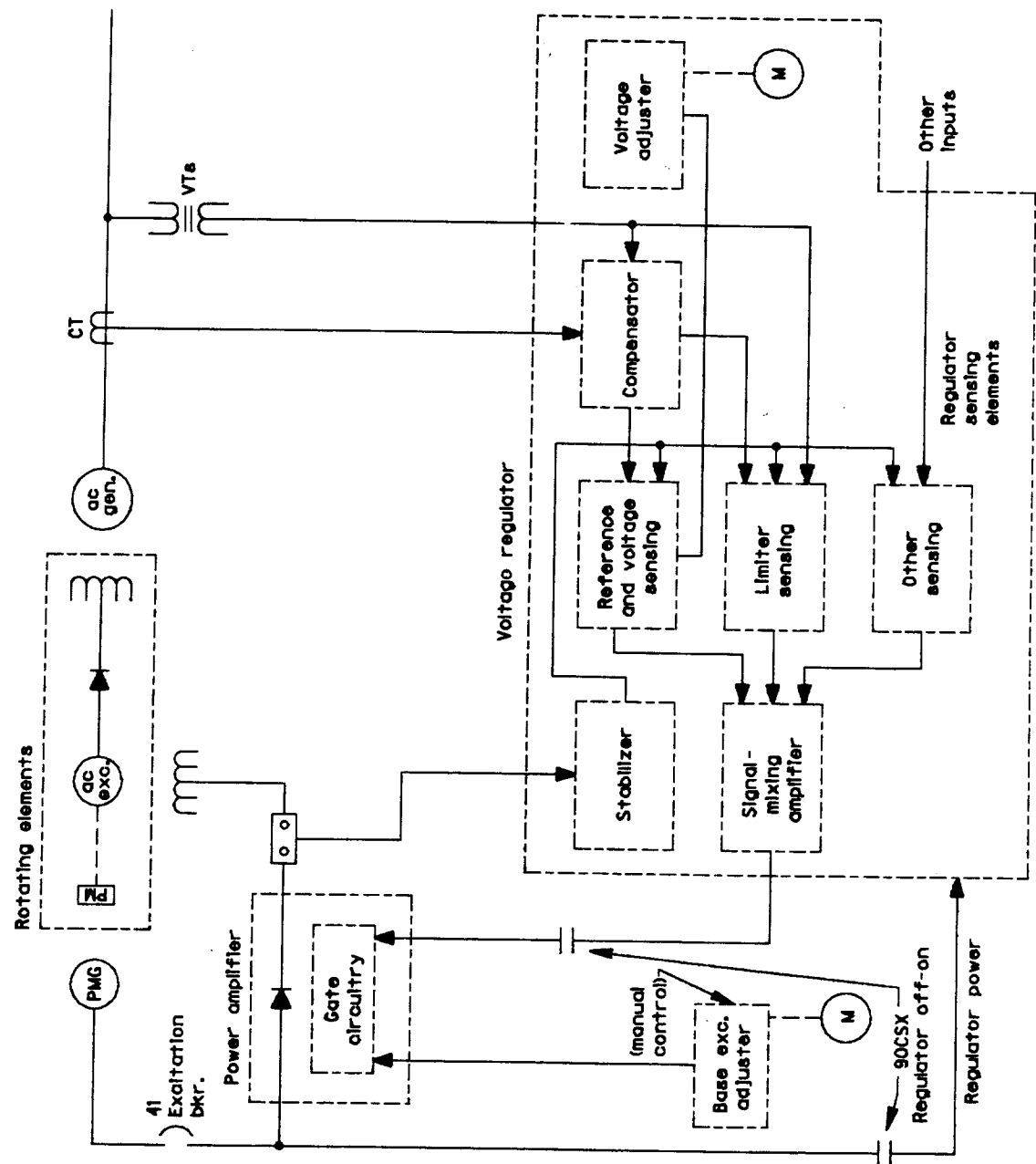


Figure 1-15 Excitation Control System With Alternator-Rectifier Exciter Using Rotating Noncontrolled Rectifiers

to the generator. The bearings have babbitted surfaces in contact with the journals and are provided with oil deflectors or oil seals to confine lubricating oil within the bearing cavities. The bearings may be supported in the end bells by bearing rings or tilting pads, depending on the design. Shaft seals of bronze or babbitt are used at each end of hydrogen-cooled generators. Plain bearings may be used, in which case the bearings are supported uniformly around the outer bearing shell by bearing rings or by supports machined in the bearing bracket. Tilting pad bearings are now frequently used to overcome the mechanical and associated vibration problems caused by the unloading of bearings (due to changes in elevation or coupling alignment and consequent oil whip or oil whirl).

The babbitt must be tightly bonded to the steel bearing shell to avoid vibration problems. The babbitt may be poured into the shell, with appropriate fixtures, while the shell is stationary. Alternatively, a spin-casting technique may be used to obtain a better-quality bearing in which the impurities in the babbitt tend to be nearer the bearing axis and can be machined out. Extra babbitt stock may be left in the bearing after recasting to permit final machining after the journal diameter is checked.

HYDRAULIC TURBINE GENERATORS AND GENERATOR/MOTORS

Babbitt-lined bearings of the sleeve type with cylindrical seats—similar to the journal bearings described above—are normally used for guide bearings. The arrangements of guide bearings in different types of machines are shown in Section 1.4. The guide bearings must be capable of handling both directions of rotation on generator/motors.

Horizontal generators will usually be equipped with babbitted journal bearings. These generators have arrangements that enable them to take thrust loads either in the generator or hydraulic turbine bearings.

Thrust bearings are normally separate from guide bearings in vertical machines. The thrust bearing is at the top of the generator in a suspended design and at the bottom of the generator in an umbrella design. One type of thrust bearing uses a pivoted shoe to support the load. The babbitt-lined shoes are also called segments, and this type of bearing may be called a Kingsbury thrust bearing. Another type of thrust bearing

uses springs rather than pivots under segments of a circumferential plate. The springs may be compressed. A typical spring-type thrust bearing is shown in Figure 1-16.

The Kingsbury spherical bearing serves as both a thrust bearing and a guide bearing and does so in one unit. This type requires no radial clearance; hence it brings about true running of the shaft in the sphere center and avoids the gyrating action (or "skate") that is noticeable at the upper end of the shaft of a hydroelectric generator mounted in the usual guide bearings.

Guide and thrust bearings may be self-cooled in smaller machines. Larger generators require water-supplied cooling coils in the oil baths (or pots) to remove the heat of friction, particularly from heavily loaded thrust bearings. The largest machines of recent vintage use direct water cooling of the shoes or segments plus temperature control of the lubricating oil.

Figure 1-17 shows a typical guide bearing.

INSULATION

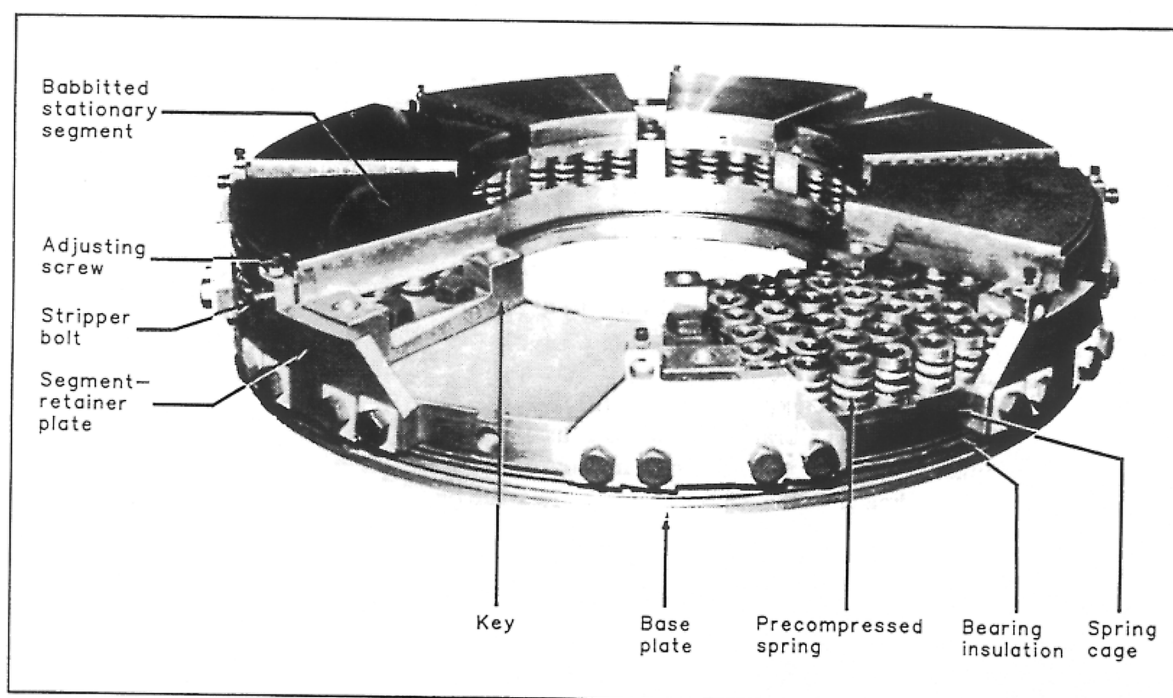
Magnetic dissymmetry in the generator and other sources noted in Section 1.3 can produce shaft voltages, which in turn can produce shaft currents. To prevent such currents from flowing, insulation is normally used on non-drive-end bearings, oil deflectors, hydrogen seals, and couplings.

Bearing insulation may be in a single layer at the nondrive end. Checking the resistance of the insulation requires isolating the shaft from grounds from other bearings, oil deflectors or seals, hydrogen seals, and couplings to the turbine and excitors.

Alternatively, bearings may be insulated on the nondrive end by double-layer or sandwich-type insulation, in which a metal conductor is sandwiched between insulation. The insulation resistance can be checked from the metal conductor to ground without breaking couplings or isolating other bearings.

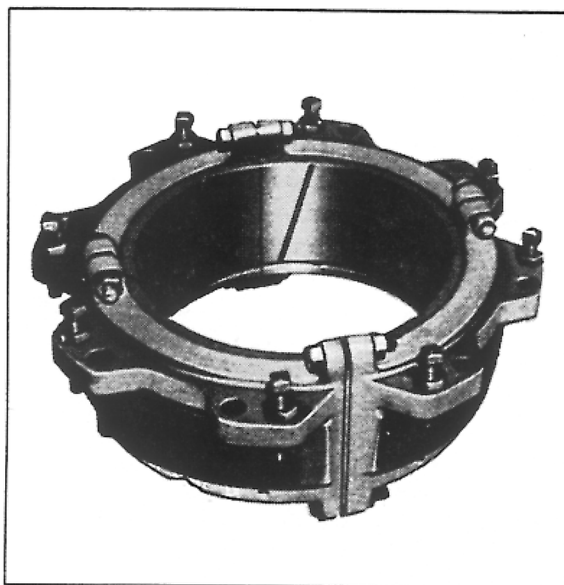
Some manufacturers insulate both the drive-end and non-drive-end bearings.

The insulation materials are mechanically strong and are formed from fiberglass, linen, or similar bases that are laminated and then impregnated with various types of resin, such as phenolics, epoxies, or polyesters. The material should resist moisture and penetration by oil and carbon. These insulation materials can be machined for fitting to the generator components. The materials come in sheets, tubes, and rods for shaping into



SOURCE: *Instructions for Large Vertical Synchronous Generators*. Schenectady, N.Y.: General Electric Company, 1959, GEH-527H, p. 27, Figure 3-7.

Figure 1-16 Thrust Bearing With Two Segments and One Group of Springs Removed



SOURCE: *Hydraulic Turbine-Driven Synchronous Generators and Large Vertical Motors*. New York: Allis Chalmers, p. 16.

Figure 1-17 Typical Guide Bearings

insulation for bearing rings or pads, bolt sleeves, and washers.

Certain manufacturers specify that the insulation resistance of the stator-to-shaft insulation system should be 10 MΩ or greater. Other manufacturers recommend a minimum of 1 MΩ. As generator reassembly begins, maintenance personnel may have a satisfactory insulation resistance, but this value will decrease as more and more components are assembled. Judgment must be used to arrive at a value that is acceptable, taking into consideration that the maximum shaft voltage at rated load and power factor may be on the order of 20 to 30 V for very large generators. One factor to consider is cleanliness; it is most important to avoid bridging thin layers of insulation with dirt, metal particles, or other contaminants.

VIBRATION

Bearings and vibration are normally associated, not necessarily because the bearings cause vibration but because the vibration sensors or pickups are mounted on the bearing caps or go through the bearing as shaft-riding pickups.

Vibration can be described as mechanical motion or oscillation about a reference point of equilibrium. The characteristics of vibration can be defined by amplitude, frequency, and phase.

- Amplitude indicates how much vibration is present. Three parameters can be used to measure vibration amplitude: displacement, velocity, and acceleration. Displacement indicates the magnitude of a motion, shows how much a part is vibrating, and is normally measured in mils peak to peak (1 mil = 0.001 in.). Velocity is the rate of change of displacement and is the first derivative of displacement as a function of time. Velocity is an indication of the destructive energy of a vibrating part and is usually measured in peak inches per second. Acceleration, the time rate of change of velocity, is an indication of the forces acting on a part. Acceleration magnitude is proportional to displacement and the square of the frequency of vibration; it is measured in terms of gravity (g).
- Frequency is the number of vibration cycles in a given period of time and is usually expressed in cycles per minute or cycles per second (Hz).
- Phase compares the position of the vibrating part at a given instant with a fixed point or another vibrating part. Phase is normally expressed in degrees, where one complete cycle of vibration equals 360°. The term *angle* is often used instead of phase.

Table 1-1 shows the causes of vibration, most of which are mechanical. Electrical problems often appear to be mechanical problems. One example is shorted turns or coils on a rotor that show symptoms similar to those of a bent shaft because of unequal temperatures that exist radially across the rotor. A loose stator core will cause vibration and significantly increase noise levels in the stator casing and foundation. Stator winding single-phasing and bypassed coils or groups of coils will also increase vibration and noise levels.

In Table 1-1, the term *resonance* also means natural frequency, reed frequency, and critical speed.

Figure 1-18 shows acceptable and unacceptable vibration displacement as a function of speed. This chart will be useful to both maintenance and operation personnel.

Many new methods of taking and analyzing vibration data have been developed by specialty companies in this field. Tape recorders can be used for data gathering and for permanent records. Spectrum analyzers and computers can be used to process the data and to perform modal analysis, thereby helping resolve vibration problems on both generators and prime movers.

1.9 APPLICATION

Generators are designed for application to utility systems or to specific types of electrical loads. The prime mover, generator, and electrical load should be a coordinated package. Prime movers to drive the generators include steam, hydraulic, gas, and wind turbines and diesel, natural gas, or gasoline engines. Loads can be utility systems, manufacturing facilities, or a cogeneration combination of both. The loads may involve peaking, cycling, and emergency conditions.

The generator should be specified and applied to meet the expected type of loading for the life of the machine. This loading may include base loading, peak loading, cycling, or combinations thereof, depending on the prime mover's age, condition, and efficiency. An important factor in generator application is the unit transformer, which is the link to the power system. The coordination of the generator and the unit transformer is described in Volume 2, *Power Transformers*. The generator should be sized for the maximum power available from the prime mover. With steam turbine generators, the maximum power available is normally obtained from the heat-balance study.

After some years of operation, generators may be rewound because of changes in the prime mover, changes in the application (such as cycling), or deterioration of the stator or rotor windings. The generators may be rewound for higher ratings through the use of higher-temperature insulation materials or redesign of the windings. Listed below are the factors that should be considered in applying generators:

- Type of prime mover and direction of rotation
- Type of load
 - Baseload
 - Peaking
 - Cycling
 - Plant startup
 - Emergency
- Electrical requirements
 - Kilovolt-amperes
 - Kilowatts
 - Voltage
 - Power factor
 - Phases
 - Phase sequence

Table 1.1 Typical Vibration Sources

Probable Cause	Frequency Related to Machine RPM	Dominant Direction of Vibration; Amplitude	Notes
Unbalance	$\text{rpm} \times 1$	Radial; steady	Unbalance is the most common cause of vibration.
Bent shaft	$\text{rpm} \times 1$ (or $\times 2$)	Axial; high	The strobe picture depends on the machine; it usually shows unsteady vibration.
Antifriction bearings	$\text{rpm} \times 20$ to $\text{rpm} \times 50$	Radial; low	Use the velocity mode to analyze vibration.
Sleeve bearings	$\text{rpm} \times 1$	Shaft-bearing	Compare the shaft and bearing readings.
Misalignment	$\text{rpm} \times 2$	Axial; high	The axial amplitude equals 0.7 or higher of the vertical or horizontal amplitude.
Faulty belts	$\text{rpm} \times 1$ to $\text{rpm} \times 5$ (belt $\text{rpm} \times 2$)	Radial; unsteady	Freeze faulty belts with a strobe and observe their performance.
Oil whip	Less than machine rpm	Radial; unsteady, sometimes severe	Frequency is near one-half the machine rpm. Oil temperature or viscosity may be factors.
Gears	High (related to number of gear teeth)	Radial; low	Use the velocity mode to analyze vibration.
Looseness	$\text{rpm} \times 2$	Proportional to looseness	Looseness is frequently coupled with misalignment.
Foundation failure	Unsteady	Erratic	Foundation failures show up during balancing.
Resonance	Specific "criticals"	High	Vibration increases at critical speeds.
Beat frequency	Periodically varying	Pulsating	This problem is caused by close rpm machines.

- Frequency
- Speed
- Excitation system (including the voltage regulator)
- Electrical characteristics
 - Reactances
 - Resistances
 - Time constants
- Usual service conditions
 - Environment (including ambient or coolant temperatures)
 - Altitude
 - Bases and enclosures
- Unusual service conditions
 - Exposure to dust, lint, chemicals, moisture, rodents, high temperatures, shock, vibration, and mechanical loading from external sources.
 - Deviations from rated voltage, frequency, and current and voltage balance (negative sequence currents, I_2).
 - Exposure to electrical faults, switching events, torsional stresses, and operation errors.
 - Over- or underexcitation that exceeds the reactive thermal capability of the machine.

(Figure 1-19 shows a typical reactive capability curve.) For the voltage regulator on manual control, underexcitation may cause generator instability. Figure 1-19 indicates the stability limit for a given electrical system and generator on manual voltage control. The stability limit depends on the system and generator design; thus the dotted curve in Figure 1-19 is shown for descriptive purposes only.

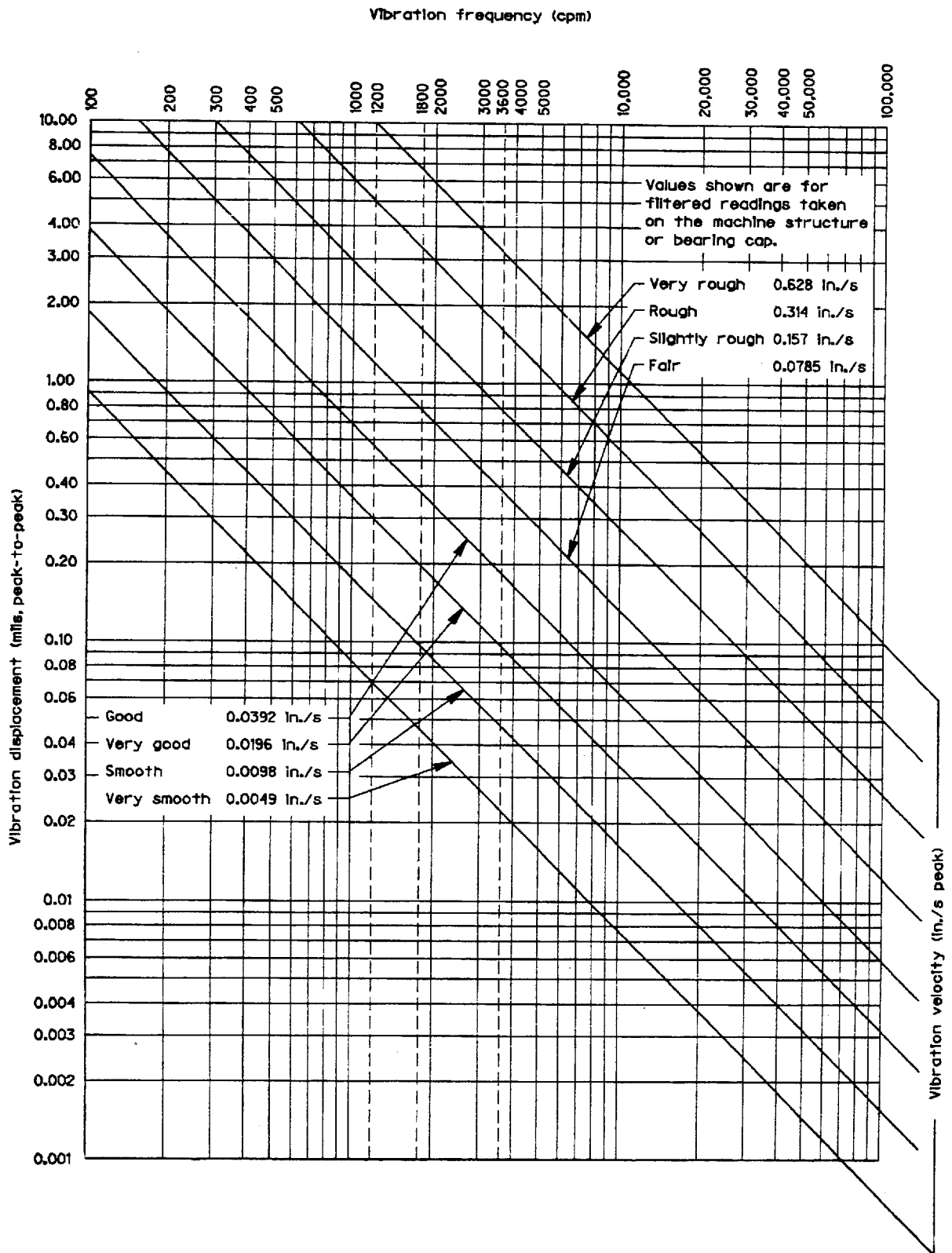
- Protection from electrical events or physical conditions that may damage the generator

Volume 8, *Station Protection*, contains information about generator protection applications.

Among the studies necessary to ensure that generators are correctly applied are:

- Short-circuit, fault, and relay protection
- Stability studies
- Subsynchronous resonance (normally associated with series capacitance compensation applied to transmission systems)

Stability is the condition of a generator and prime mover in which mechanical power equals electrical power. The power limit, or stability limit, is the critical value of power transfer between



Courtesy of IRD Mechanical, Inc., Columbus, Ohio, U.S.A.

Figure 1-18 Vibration Severity Chart

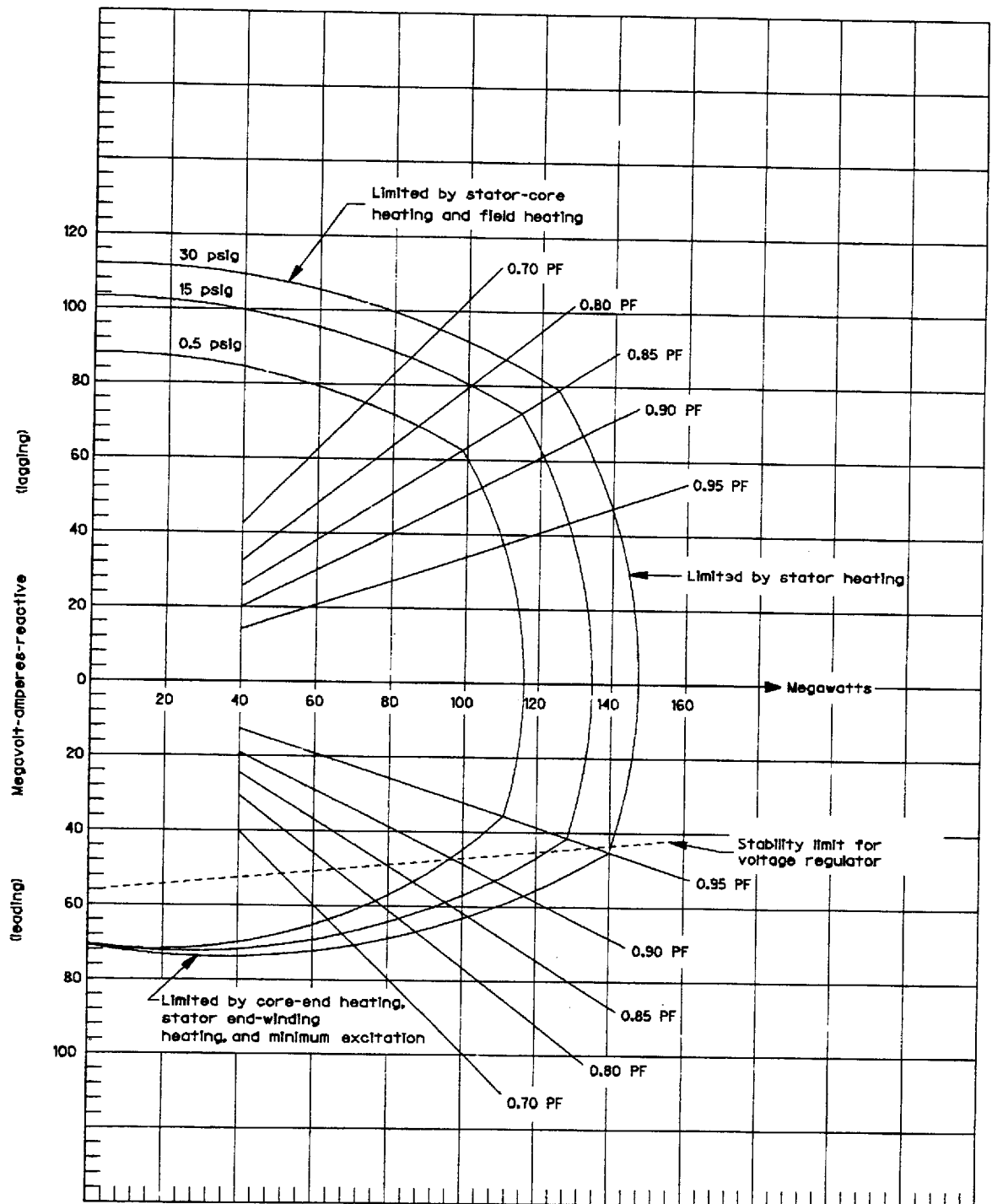


Figure 1-19 Generator Reactive Capability Curve

machines, or between groups of machines, below which the system is stable and above which the system is unstable. Stability problems are generally divided into three major categories:

- **Steady-state stability**, in which system load changes are made so slowly in response to natural oscillations (or rates of change in the flux of rotating machines) that the system may be regarded as remaining in normal steady-state operation
- **Transient stability**, in which load changes are made abruptly, or the system is shocked by faults or switching operations
- **Hunting or sustained oscillations** between machines, which may result from problems with governors, voltage regulators, or an abnormal system condition, such as an out-of-service transmission line.

STABILITY STUDY PARAMETERS

Stability studies are made from factory-supplied parameters that may result from tests or calculations. See a text such as *Power System Stability* (5) for power system stability calculations based on the parameters below. For complete definitions of terms, see IEEE Standard 100-1984 (6).

- WR^2 = generator and turbine rotational inertia (lb-ft²)
- X_d = direct-axis synchronous reactance (unsaturated; rated current)
- X'_{di} = direct-axis transient reactance (unsaturated; rated current)
- X'_{dv} = direct-axis transient reactance (saturated; rated voltage)
- X''_{di} = direct-axis subtransient reactance (unsaturated; rated current)
- X''_{qi} = quadrature-axis subtransient reactance (unsaturated; rated current)
- X''_{dv} = direct-axis subtransient reactance (saturated; rated voltage)
- X''_{qv} = quadrature-axis subtransient reactance (saturated; rated voltage)
- X_{2v} = negative-sequence reactance (saturated; rated voltage)
- X_q = quadrature-axis synchronous reactance (unsaturated; rated current)

X'_q = quadrature-axis transient reactance (unsaturated; rated current)

X_0 = zero-sequence reactance

X_{lm} = armature leakage reactance (saturated; rated voltage)

X_p = potier reactance (saturated; rated voltage)

R_1 = positive-sequence resistance

R_2 = negative-sequence resistance

The following estimated items are in seconds at 100°C (armature) or 125°C (field).

T'_{do} = direct-axis, open-circuit transient time constant

T''_{do} = direct-axis, open-circuit subtransient time constant

T_{a3} = short-circuit time constant of armature winding

T'_{qo} = quadrature-axis, open-circuit transient time constant

T''_{qo} = quadrature-axis, open-circuit subtransient time constant

1.10 MONITORING

Electrical and physical data monitored during operation can be observed, recorded, analyzed, trended, alarmed, and relayed to determine a generator's condition and protect the machine from operating problems and failures. Many of these outputs are noted below.

ELECTRICAL QUANTITIES

Stator Current Stator current can be monitored to ensure that it does not exceed rated levels and that the three phases are balanced within the limits specified. Unbalanced currents cause negative-sequence currents (I_2) to flow; high levels of unbalanced stator current can damage the rotor. A cylindrical rotor generator, for example, may be equipped with a negative-sequence relay, which will give an alarm when I_2 exceeds 30% for indirectly cooled rotors and 10% for directly cooled rotors. Currents from stator current transformers are supplied to protective relays for overcurrent, low-frequency overcurrent, and differential fault protection. Stator currents flowing to ground during a ground fault normally trip the

generator from relays in the generator neutral grounding scheme. (Volume 8, *Station Protection*, provides a detailed description of protective relays.)

Stator Voltage Stator voltage can be monitored to ensure that it does not exceed rated levels (normally $\pm 5\%$) and to ensure proper phase voltage balance. Phase unbalance will cause current unbalance and negative-sequence currents (I_2), which can damage the rotor. ANSI/IEEE Standard C50.13-1977 (7) specifies the limits of I_2 for continuous operation and for short-time operation (T_2^2). Stator voltage related to frequency is a critical characteristic called volts per hertz. The limit of volts per hertz for both a generator and transformers connected to the generator bus is 1.05 per unit at rated load. The transformer limit is 1.10 per unit at no load. The generator will have greater volts-per-hertz capability than the unit-connected transformers. Exceeding these volts-per-hertz limits may cause the core iron to saturate, overheat, and fail. In addition, magnetic fluxes may link structural components, causing overheating and failures.

Stator Kilowatts, Kilovolt-Amperes-Reactive, and Power Factor Stator kilowatts, kilovolt-amperes-reactive, and power factor are all interrelated. These three electrical characteristics can be observed so as not to exceed the generator rating and to avoid the risk of failure. The capability curve (Figure 1-19) for a typical generator shows the limits of kilowatts, kilovolt-amperes-reactive and power factor, and the three areas of a generator that would be damaged from exceeding the limits. A generator should always be operated within its capability curve. For hydrogen-cooled machines, attention must also be paid to the hydrogen pressures and associated capability curves. Generators should be operated to avoid supplying high VARs (or lagging VARs) to a system that may have to absorb the VARs with other generators, synchronous condensers, or static capacitor banks. High VARs cause unnecessary I^2R losses in the system. On the other hand, operating with too few VARs (or leading VARs) can cause low system voltage and possible generator instability.

Rotor Current Rotor current can be monitored for most generators other than brushless excitation systems. The relationship of rotor (or field) current to stator voltage is shown on the open-circuit saturation curve (Figure 1-20). The relationship of rotor current to stator load and power

factor is shown on the V curves (Figure 1-21). Exceeding the rotor current rating when off-line, for open-circuit amperes-field-no-load, has destroyed generator stators (and can damage transformers connected to the generator bus) because of excessive magnetic flux. Exceeding the rotor current rating on-line can overheat the rotor and stator windings and can cause volts-per-hertz overheating of the stator core iron and transformers connected to the generator bus.

Rotor Voltage Rotor voltage can be observed in systems other than brushless excitation systems to determine that the value is within expected limits. In addition, the rotor voltage and current can be used to calculate a rotor winding resistance and to record the rotor temperature. These temperatures are useful for the following tasks:

- To ensure that the rotor winding insulation is not overheated
- To observe step changes (other than changes related to excitation-level changes) that could indicate field-winding turn or coil shorts and possible vibration problems caused by associated thermal changes
- To look for erratic temperature changes (or "paintbrushing") that may indicate incipient or existing arcing failures of collector-ring or exciter carbon brushes or brush rigging

Rotor Ground Detection Rotor ground detection for rotors other than brushless excitation systems is provided by a ground detection relay. Some utilities trip the unit for a rotor-winding ground, while others alarm for this event and then remove the unit from service on a planned shutdown. (See Section 1.14 for a discussion of rotor grounds. Volume 8, *Station Protection*, provides more details on the rotor ground detection relays.)

The ground detection relay applies a small direct voltage between the rotor winding and ground. When the insulation resistance to ground decreases to a low enough level, the ground detection relay will pick up and either trip the unit or sound a "rotor winding grounded" alarm.

TEMPERATURES

Temperatures of most critical areas of a generator, in addition to the rotor temperature noted above, must be monitored to avoid damage and failures. To avoid damage to windings, insulation, wedges, blocks, ties, and winding support components,

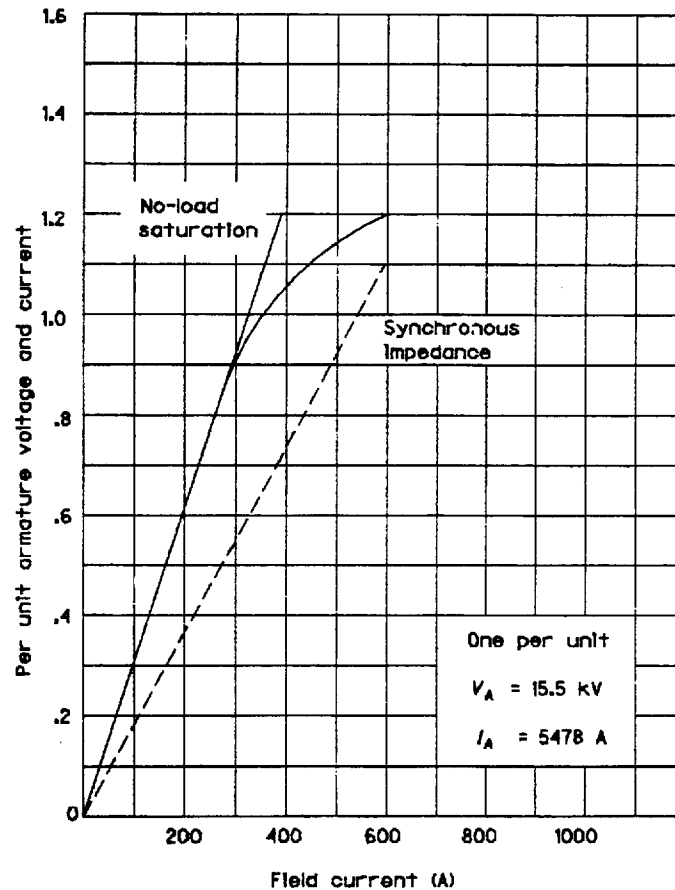


Figure 1-20 Generator Saturation Curve

maximum temperature limits must not be exceeded. The ANSI and IEEE C50 standards series presents data on standard temperature limits (see Section 1.17). Maximum limits are also critical to core iron, flux shields, through-bolt insulation, and structural components. Minimum temperatures, such as 30°C cold gas for hydrogen-cooled turbine generators, are also critical to avoid extremes of temperatures, associated thermal cycling and possible field forging, condensation, or winding insulation problems. The following temperatures are of concern:

- Rotor-winding temperature.
- Stator-winding temperature as measured by resistance temperature detectors (RTDs).
- Stator-winding inlet and outlet liquid temperatures as measured by thermocouples (direct-liquid-cooled stator windings). Differential limits among these temperatures are critical.
- Stator-winding inlet and outlet hydrogen temperatures (direct-hydrogen-cooled stator windings). Differential limits among these temperatures are also critical.

- Cooler inlet and outlet air or hydrogen temperatures.
- Cooler inlet and outlet water temperatures.
- Core-end or flux-shield temperatures. This problem usually occurs only at leading power factor operation. A core-end thermocouple is necessary to measure these temperatures.
- Collector-ring cooling-air inlet and outlet temperatures.
- Excitation system temperatures.

FLAWS

Airflows Airflows can be observed through air-cooled machines to check for restrictions that can cause overheating. Differential pressures, usually inches of water or water gage, can be checked across the fans, coolers, and filters (where used) to look for blockage.

Hydrogen Flows Hydrogen flows through hydrogen-cooled generators can be checked by observing the fan pressure differential and the

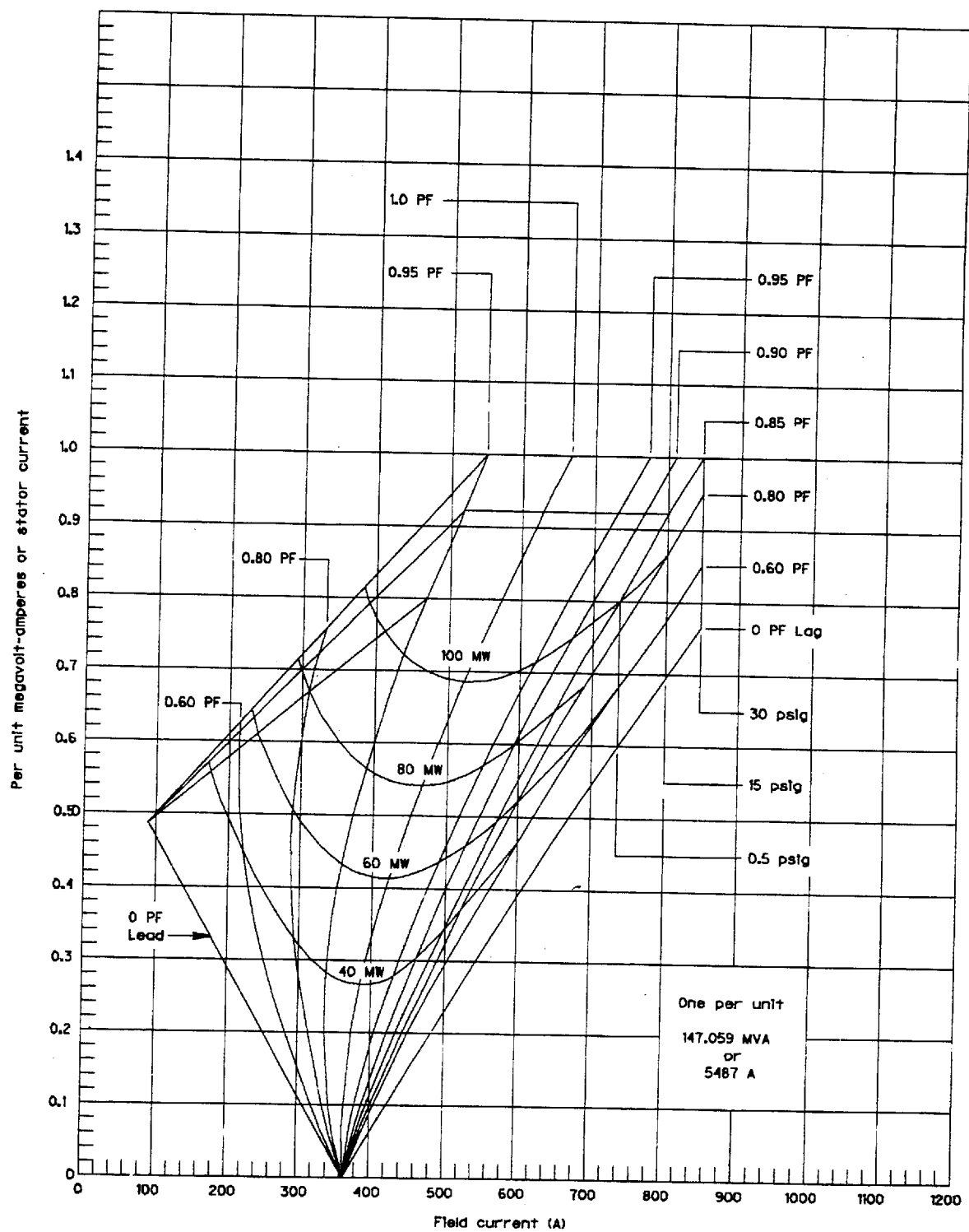


Figure 1-21 Generator V Curve

ΔT (temperature changes) across the hydrogen coolers.

Water Flows Water flows can be monitored through air-to-water, hydrogen-to-water, stator water-to-water, and stator oil-to-water coolers. Care must be exercised not only to avoid overheating generator components but also to prevent chilling, thermal shocking, and thermal cycling, which can also be detrimental to a generator.

For direct-water-cooled stator windings, water flow is particularly critical. Loss of water flow to the stator windings will normally cause a unit trip. Reduced water flow may either cause a load run-back, an alarm, or a unit trip, depending on the generator control design. Reduced water flow or even normal water flow with too high an inlet temperature can damage or induce failure in a stator winding, particularly if the water exceeds 100°C at atmospheric outlet pressure from the stator winding. The water will be boiling in such a case and will remove very little heat from the stator winding; it will thereby cause winding damage in the outlet end of the stator windings. Boiling water may also cause a flashover in the Teflon hose.

PRESSURES

Water Pressures Water pressures to coolers—whether for air, hydrogen, or stator water cooling—must provide sufficient flow through the coolers to cool the machine. If inlet pressures meet design values but cooling is not adequate, restrictions are indicated in the coolers.

Hydrogen Pressures Hydrogen pressures in hydrogen-cooled generators can be observed to ensure that they adhere to limits prescribed by the capability curves for kilowatts and kilovolt-amperes-reactive. Operating at loads beyond these curves for the specified hydrogen pressures will cause overheating in generator components, as noted on the typical capability curve in Figure 1-19). Operating at higher hydrogen pressures than those required by the capability curves may cause unnecessary use of hydrogen and problems in maintaining a shaft seal at the hydrogen seals. Low-hydrogen-pressure alarms may be used to alert the operator that an unsafe condition may exist.

HYDROGEN CHARACTERISTICS

Hydrogen Purity Hydrogen purity must be monitored in hydrogen-cooled generators to

ensure that an explosive mixture of hydrogen and air does not develop. The explosive range is 5% to 75% hydrogen in air. The hydrogen purity meter normally alarms when the purity decreases to 90%. Purity can be increased by purging the generator with new hydrogen. It is not unusual for purity to decrease for nonvacuum-degassing seal-oil systems unless leakage is sufficient to keep the purity high. Purity decrements in the vacuum-degassing seal-oil system are not normal and indicate a problem with the vacuum system. In any type of seal-oil system, contamination of the makeup hydrogen or contamination from the seal oil carrying impurities (such as moisture) into the generator will cause the purity to decrease.

The generator casing is designed to withstand a hydrogen explosion so that the operating personnel are protected. However, serious damage to the generator's internal components can result from the shock wave of a hydrogen explosion. For example, the fans may be bent, baffles may be destroyed, and cooler tubes may be severely damaged from the shock wave.

Hydrogen Moisture Hydrogen moisture should be checked to avoid problems with generator stators, rotors, and coolers. The dew point of the hydrogen should not be greater than 30°F. Moisture in the hydrogen can come from the following sources:

- Hydrogen cooler leaks
- Stator water system leaks
- Water carried in from the seal-oil system
- Moisture in the makeup hydrogen

Hydrogen dryers are provided by some manufacturers, while other manufacturers rely on dry makeup hydrogen and, in some cases, vacuum degassing of the seal-oil system to keep moisture out.

Moisture in the hydrogen can cause many serious problems inside the generator. These problems include the following:

- Corrosion of rotor nonmagnetic or magnetic retaining and zone rings. This corrosion may produce cracks and ring failures.
- Carbonate development from welding fluxes used on the hydrogen coolers. (This carbonate has been deposited on the stator windings of some generators, where it has caused a stator-winding failure.)
- Corrosion of core iron, cooler supports and other structural components, magnetic and

nonmagnetic wedges in the rotor field, and the rotor forging. (The hydrogen carries the corrosion material, rust, over to the stator and rotor windings; the material then causes insulation problems.)

- Insulation deterioration from moisture.

Hydrogen Gas Analysis Hydrogen gas analysis by gas chromatograph has been attempted by one utility to determine whether products of pyrolysis could be found. Some machines are painted with different pyrolytic tags to help the gas chromatograph identify where overheating is occurring. Such products indicate the development of incipient faults. The results of sampling 24 generators for several months were inconclusive, and the program was discontinued.

LEAKAGE DETECTORS

Liquid leakage into a machine, both water and oil, can be monitored by collecting the liquid at the bottom of the generator and piping it to a float switch, which will provide an alarm. If an alarm sounds, either on-line or off-line, the type and amount of liquid should be investigated immediately. There have been instances in which water from leaks or oil from hydrogen-seal-oil systems have backed up into generators, causing cooling and insulation problems. One such cooling problem is associated with hydrogen-cooled generator bushings. These must be blown free of liquid, if the bushing well is flooded to avoid bushing overheating. Wetting the stator windings or rotor windings may cause cooling problems and potential electrical faults from low values of insulation resistance.

STATOR WATER SYSTEMS

The flow of very low conductivity water ("fine water" or deionized water) is critical, as noted in the preceding section on flows. The conductivity of this water, which is in direct contact with the stator windings, is also critical and is normally recorded. Conductivity may be shown as micromhos per centimeter with a normal value of 0.5 or less when the stator water deionizers are working properly and there are no leaks into the stator water system.

Alarms on the recorder may be set at 5 or 10 micromhos/cm with a trip set for 20 to 50 micromhos/cm.

Leaks into the stator water system can be caused by a loose piece of material vibrating into the insulation and hollow strands of the stator bars. A high rate of hydrogen usage results, and such leakage should be investigated immediately; winding failure could occur at any time depending on the location. Excessive hydrogen leakage into the stator water system can be caused by a hole in the stator copper, hoses, or internal water piping.

The stator water conductivity can be used as an indicator of a stator water system leak when the hydrogen pressure is greater than the stator water pressure. The conductivity will increase because the hydrogen carries dust and other contaminants into the stator water system, not because of the hydrogen itself. In addition, hydrogen or an explosive mixture of hydrogen and air will appear in the vent from the stator water system.

When the generator is degassed, water from a stator water system leak will drain into the leakage detector. The stator water deionizer should be isolated when the generator is degassed to avoid poisoning the deionizer resins with carbon dioxide during degassing.

CONDITION MONITORS

Generator condition monitors use an ion-chamber detector through which hydrogen gas is continuously passed and tested for decomposition products caused by arcing or overheating of insulation on the core laminations or windings. The monitors are set to alarm for certain levels of decomposition products and to confirm by test that the alarm is valid. Some of these monitors will also collect a sample of gas pyrolysis products on a filter medium for laboratory analysis. Once an alarm is validated, the operator must decide whether to reduce the load to see if the alarm clears or to remove the unit from service for further investigation. If properly tuned and maintained, the condition monitor may provide an early warning of incipient faults and prevent a major failure.

RADIO FREQUENCY OR ELECTROMAGNETIC INTERFERENCE MONITORS

Radio frequency or electromagnetic interference monitors have been developed in recent years to detect high-frequency signals in generator windings. The signals can be picked up by current transformers, capacitors, resistors, or antennas,

usually at the generator neutral. Development work is also under way on coupling devices—inside the machine or on the line leads or buses—and on antennas or probes inside the generator. Certain frequencies may be related to partial discharge (corona), gap discharge, microsparking, and arcing. The level of activity associated with specific frequencies or bands of frequencies may be used to determine the need for repairs to insulation or winding copper (because of strand arcing). EPRI report NP-902 (8) provides detailed information about this subject.

Radio frequency monitors have also been developed to detect carbon-brush sparking at collector rings and dc generator exciters. One device employs an antenna to detect radio waves emitted by sparking. The data are processed and then fed to a recorder with an alarm function to alert the operator when excessive sparking occurs.

VIBRATION

Bearings Bearing or machine vibration can be monitored by detectors placed on the bearing caps or by shaft-riding pickups. Vibration limits are set depending on the location of the detector and the speed of the generator. Values are specified for alarming, balancing required, and tripping. Typical values for a 3600-rpm turbine generator with shaft-riding pickups are 5 mils (peak to peak) for alarm, 7 mils for balancing required, and 10 mils for tripping. Different manufacturers specify different limits.

Shaft Torsional Vibration Shaft torsional vibration has become a major subject for technical study in recent years, following two incidents of broken generator shafts at a western U.S. utility. The unit was connected to transmission lines with series capacitance compensation. One EPRI-sponsored study (9) resulted in the development of a torsional vibration monitoring system by a major U.S. manufacturer.

End Windings End-winding vibration can be monitored by use of fiber-optic pickups mounted on generator coils or end-winding structural components. The fiber optics provide insulation for bringing out vibration data. Levels of about 2 mils peak to peak are considered normal and acceptable. Levels greater than 8 mils are causes for concern, indicating that maintenance and tightening of the end windings may be required and/or that

resonance at running speed may exist and structural changes in the generator structure or end-winding supports may be necessary.

SHAFT VOLTAGE

"Cylindrical Rotor Construction" in Section 1.3 explains the causes of shaft voltage. "Investigating Generator Electrical Trips" in Section 1.14 describes how to check rotor-shaft voltages and ground rotor shafts.

1.11 OPERATION AND OPERATION ERRORS

Generators that are well designed, correctly applied to the prime mover and the connected load, and operated with a reasonable amount of care will normally have a long and useful life. Abuse or incorrect operation, however, can cause failures in a very short period. The suggestions offered below should help lengthen generator life and avoid failures.

OPERATING INCIDENTS

Despite the best training programs using manufacturers' instructions and materials, and despite experienced instructors, operating incidents occur that frequently cause generator and exciter damage. For example:

- Generators are synchronized out of phase.
- Dc exciters are incorrectly paralleled.
- Excitation is allowed to rise too much or to fall to unstable levels.
- Grounding leads are inadvertently left on generator buses.
- Generators are started across the line from standstill.
- Carbon brushes are allowed to become too short.
- Generator disconnects are opened while there is still voltage on the machine.
- Automatic voltage regulators are tripped, allowing overvoltage from manual regulator settings.
- Generators are single-phased because of stuck circuit breakers.
- Hydrogen and stator water systems are operated outside allowable pressure and temperature limits.

Edison Electric Institute reports have detailed many operating incidents. ANSI/IEEE Standard 67-1972 (10) and IEEE Standard 492-1974 (1) have major sections on the safe operation of turbine generators and hydrogenerators, respectively.

NORMAL OPERATION

Generators should be operated within the limits of electrical specifications, temperatures, flows, pressures, and other physical conditions as shown on the nameplate and in instruction books. Most of these parameters are described in Section 1.10. Note that there must be concern for high limits, low limits, and swings or trends within and outside high and low limits.

Operators should be made aware of the limits to be followed for normal operation. Alarms should be provided for variations from normal operating limits. Relays and tripping schemes should be installed for serious variations from normal limits where there is risk of damage or where faults have occurred.

SYNCHRONIZING GENERATORS

Instrumentation is required for synchronizing or paralleling synchronous generators with systems already in service. The instruments include a synchroscope and/or indicating lamps to determine when the starting, or incoming, generator is in phase with the system. A frequency or speed meter is required to ensure that the incoming machine is at the correct speed for synchronizing. A voltmeter is necessary to ensure that the incoming machine voltages (all three phases) are at the correct level for synchronizing. Phase rotation is normally checked before initial synchronizing and need not be checked again unless the generator connections, buses, transformers, or potential transformers are disturbed.

Synchronizing can be automatic, using a suitable relay or manual. For automatic synchronizing, the three-phase voltages are adjusted by the operator to the correct level; then the generator speed is raised slightly above synchronous speed. The automatic relay is cut in and will adjust the speed to synchronous speed. The relays will then close the synchronizing circuit breaker slightly before the 12 o'clock position on the synchroscope after the synchroscope has completed at least one full revolution to ensure that it is working. At 12 o'clock, the incoming generator is in phase with the system. This status means that there is no

phase difference between the generator and the system and that there is zero voltage across the contacts of the circuit breaker.

Some companies require operators to use automatic synchronization; if the equipment is out of order, they require repair efforts before resorting to manual synchronization.

Other companies require manual synchronization of all generators with the use of a synchronizing check relay scheme that prevents gross synchronizing errors. Operators must be fully aware of the critical nature of this operation because generators, transformers, and other equipment can be destroyed by incorrect synchronizing operations. For manual synchronizing, the operator must perform all functions of setting the voltage levels of all three phases, adjusting the incoming generator speed and closing the synchronizing breaker slightly before the 12 o'clock position on the synchroscope after seeing at least one full revolution to ensure that the synchroscope is functioning. Paralleling lamps can also be used in place of or in addition to the synchroscope. (Carbon filament bulbs allow accurate determination of 0° closing angles.) When correctly wired, the lamps will glow at full brilliance when the incoming generator is 180° out of phase with the system and will be dark when the incoming generator is in phase with the system. The paralleling breaker is closed when the lamps are dark.

The use of paralleling lamps is not recommended, especially for large generators. A preferable method is to use a voltmeter in place of each lamp. However, the synchroscope is the best method for synchronization because it compares frequency and phase angle. Separate voltmeters are used to check that the incoming generator voltage and system voltage are the same magnitude.

It is also essential that all three voltages of the voltage regulator be checked as field excitation is increased on the unit. Field currents should also be observed and the proper correlation between field currents and stator voltages made during this period to ensure that the potential transformers are operating correctly.

Past operation errors with synchronous generators have included the following:

- Synchronizing out of phase because of operator error; malfunction of synchronizing instruments, slow closing of the paralleling circuit breaker, and manual operation of a relay to close the circuit breaker when the incoming generator is not in phase with the system.

- Adjusting the generator voltage to a level that is too high for too long. Generators are designed for $\pm 5\%$ variation from their rated voltage at rated load. Unit transformers are also designed for $\pm 5\%$ of their rated voltage at rated load. The generators and transformers will stand 1.1 per unit voltage at no load.

One large generator had severe core iron damage and winding failure when the generator voltage was erroneously adjusted to about 1.25 per unit by using only a single-phase voltage indication. The phase voltage selected to be read was too low because of a bad stab connection on one of the potential transformers. It is essential that all three phase voltages be checked to prevent overvoltage and overfluxing of the core.

Another large generator was severely damaged because of overvoltages during automatic voltage regulator (AVR) checkout at initial startup. The limit for AVR checkout (no load) is 1.1 per unit voltage. Still another was damaged during factory tests when the voltage was kept too high for too long. In each case, the generator voltages were in the range of 1.2 to 1.3 per unit.

- Synchronizing when the incoming generator had a phase rotation opposite the system phase rotation. In many cases, the stator windings are destroyed from such an event.

Induction generators do not require special instrumentation and relays for synchronizing because there is little voltage in the stator windings until excitation is supplied from the stator current. The normal way to bring an induction generator on-line is to start the prime mover first with the electrical circuit open. When the unit reaches synchronous revolutions per minute, or just slightly above, the circuit is closed. The resulting electrical and torque transients are relatively small.

Engine generators require synchronizing instruments if they are connected to an in-service system. In cases involving emergency or standby duties, these generators will pick up a dead bus; they therefore require no synchronizing equipment unless such equipment is needed to test an energized bus under load.

MOTORING CONDITIONS

Most synchronous generators are designed to be driven by a prime mover to synchronous speed,

with the voltage level, frequency, and phase adjusted and the generator synchronized to the system. Under various adverse conditions, however, a synchronous generator will be forced to operate as a synchronous motor, induction motor, or induction generator, depending on the prime mover and status of the field and generator breakers. The various modes of operation are shown in Table 1-2.

Note that several of the motoring conditions in Table 1-2 can result from erroneous operation of the prime mover, field breaker, generator breaker, or the manual or automatic voltage regulators.

One of the most serious erroneous operations is motoring a synchronous generator from standstill. This error can occur from closing the station service auxiliaries circuit breaker, generator breaker, or associated disconnect switches to the system while the unit is out of service. Motoring through the station auxiliaries system will probably destroy the unit auxiliaries transformer. The generator is started across the line as a three-phase induction motor. Heavy currents are induced in the field forging, and they flow along the rotor surface, at the edges of flexibility slots, in and out of slot wedges, and toward the ends of the rotor where they may be short-circuited by amortisseur windings or the rotor retaining rings. If the generator breaker is not tripped almost immediately by an underfrequency, breaker failure, or line relaying, serious damage to the forging will result. In one case, a generator forging was destroyed by the intense heat. In less serious cases, overheated areas and hard spots were ground out of the forgings and the rotors were reused. A particularly bad case of motoring occurred when an air blast circuit breaker arced over in the open position. The stator and rotor windings are not usually damaged by these motoring events.

OVEREXCITING GENERATOR

Serious damage can be done to a generator by applying more excitation (field current) than the generator can withstand for the load conditions specified on a reactive capability curve, such as Figure 1-19, or on the generator nameplate. The stator core iron is driven into saturation from overexcitation, and the core losses increase dramatically. If the cooling system is unable to remove the excessive heat, the stator windings will fail and the stator core may melt. The field winding can also be damaged by applying excessive field current for too long.

Table 1.2 Modes of Synchronous Generator Operation

Number	Prime Mover Condition	Speed	Generator Field	Generator Breaker (Tie to System)	Type of Electrical Machine Operation	Normal or Abnormal	Concern
1	Driving	Synchronous	On	Closed	Synchronous generator	Normal	None
2	Driving	Synchronous or above	Off*	Closed	Induction generator	Abnormal	Field forging heating
3	Not driving	Synchronous	On	Closed	Synchronous motor	Abnormal	Turbine blade and exhaust hood heating; loss of vacuum in condenser
4	Not driving	0 to below synchronous	Off	Closed	Induction motor	Abnormal	Field forging, turbine blade, and exhaust hood heating
5	Driving	0 to synchronous	On	Open	Synchronous generator	Normal for paralleling	None
6	Driving	Below synchronous	On	Open	Synchronous generator	Abnormal if AVR tries to hold generator at rated voltage while speed decreases significantly	Transformer and generator overheating because of high volts per hertz, if condition exists too long
7	Driving	Synchronous	On but underexcited below stability limit**	Closed	Synchronous generator	Abnormal	Unstable generator that slips poles; turbine tripping from overspeed

*Unit will trip if field breaker opens.

**Underexcitation can be caused by AVR or manual regulator problems, or by collector-ring or exciter flashover.

The subsection on synchronizing generators discusses several causes of overexcitation, such as from a blown potential transformer fuse, during a voltage regulator checkout and during factory tests.

Overexcitation can be caused by malfunction of the AVR. Failure of circuit components, dirty contacts on a potentiometer, a loss-of-voltage signal to the AVR, and similar problems can cause the excitation system to overexcite the generator. Erroneous operation of manual voltage regulators can also cause overexcitation.

Overexcitation of the generator must also be considered for the special case of prewarming rotor fields. Because the prewarming occurs at reduced speed, full no-load excitation should not be applied.

Most manufacturers can provide excitation-limiting circuits and volts-per-hertz protection to prevent generator damage from overexcitation. One concern in limiting excitation is that voltage support will be limited during system disturbances and system stability may be impaired.

Overexcitation can also occur during startup when the volts-per-hertz limits of the generator and connected transformers are exceeded. This

situation can develop, for example, by placing the AVR in service and setting the generator voltage to rated value at rated frequency and then allowing the generator speed to decrease. The generator, unit transformer, and unit auxiliaries transformer(s) can severely overheat if this condition exists for too long.

UNDEREXCITING GENERATOR

Underexcitation that exceeds the generator capability curve limits can be caused by malfunction of the excitation system, problems with the field winding, or operator error. The results are overheating of the structural parts of stator end windings and ends of the stator core, and/or generator instability, which will be evidenced by pole slipping and probable unit trip from overspeed or out-of-step relaying.

Underexcitation problems can be avoided by using an AVR that has underexcited-reactive-ampere-limit circuits in service. When regulating voltage manually, avoid underexcited operation.

Excitation system problems include failure of dc exciters, blown diodes or silicon-controlled rectifiers in solid-state systems, carbon-brush arcing

and flashovers of brush rigging, faults in voltage regulator circuits and components, and faults in field breakers and associated circuits.

Where generator field temperature recorders are used, an alert operator can see incipient faults developing from carbon-brush arcing by noting the "paintbrush" effect or sudden changes in the temperature line and assuring that these changes are not related to voltage changes at the time. (The field temperature recorder may also show shorted turns or coils in the generator fields by indicating step changes in field temperatures.) Underexcitation can result from generator field problems such as openings in the radial studs, bore copper, windings, or winding connections; shorted turns or coils; or double ground faults.

Operator errors can cause underexcitation by incorrect setting of the manual or automatic voltage

regulators; incorrect paralleling of main and reserve dc exciters; or failing to note carbon-brush arcing that can result in flashovers of brush rigging.

One example of an operator error is shown in Figures 1-22 and 1-23. The AVR of a 280-MW unit was out of service, and the generator was on manual regulator. The generator normally operated underexcited at night to help keep the system voltage down. Morning load pickup was started about 4:15 a.m. The operator manually increased excitation twice as load was increased but then allowed the reactive to go too far underexcited. The generator slipped poles; the stator current, voltage, and reactive swung violently; and the unit tripped automatically from excessive turbine speed, loss of field, or out-of-step relaying. No damage occurred in this event, but there is the long-term effect of coupling, shaft, and generator-

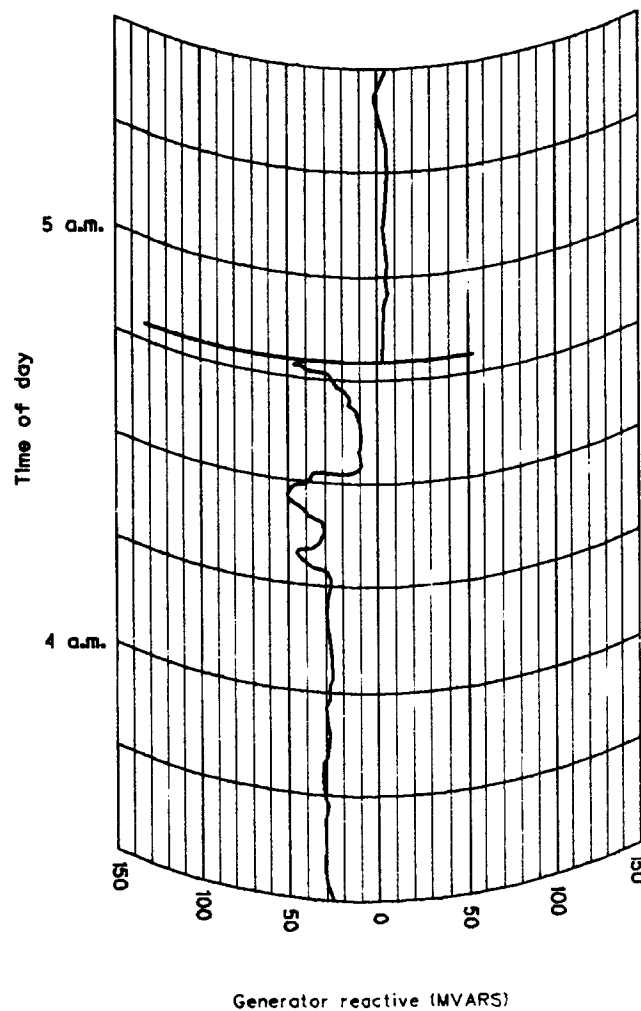


Figure 1-22 Reactive (MVAR) Chart Showing Generator Tripout From Underexcitation

winding damage resulting from this type of erroneous operation.

FAILURES OF EXTERNAL EQUIPMENT

Failures of devices that are connected to the generator can cause excessive generator currents that loosen the generator end windings. If a severe fault occurs on the generator side of connected transformers, the generator end windings should be inspected for damage. There tends to be a cushioning effect from transformer impedance for faults on transformer windings other than those directly connected to the generator buses. As a result, inspection of the end windings is not nearly so critical as for the first-noted types of faults.

Unit-connected generators without generator breakers will feed energy into faults associated with the generator buses during the field-current-

decay transient. De-excitation circuits are used on some generators to force the field current to lower levels during a fault. Such devices are employed mainly to limit the damage to the unit transformer and unit auxiliaries transformer(s) that may result from close-in or internal faults. The existing equipment applied for this purpose has limited effectiveness; future research may provide more effective methods.

Oscillograph or other records made during faults and protective relay targets should be analyzed to determine the fault current levels and used to establish the need for inspections and repairs. Phase-to-ground faults in transformers, buses, capacitors, and arresters associated with the generator may have the fault currents so limited by high-impedance generator grounding that inspections and repairs will not be required.

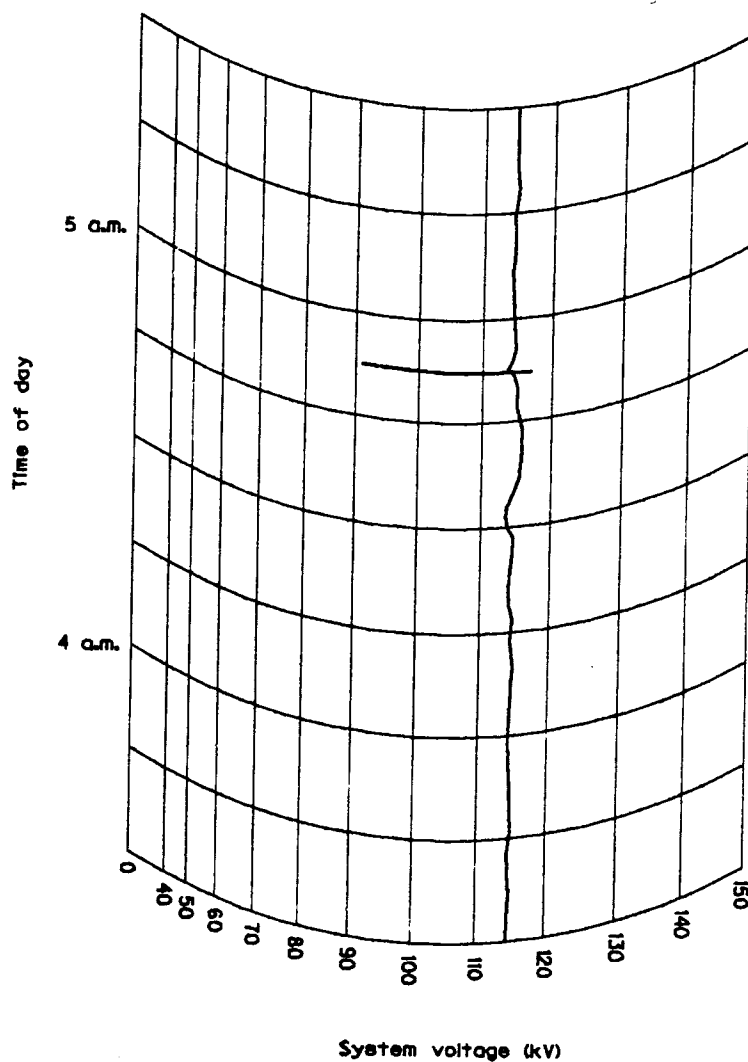


Figure 1-23 Voltage Chart Showing System Voltage When Generator in Figure 1-22 Tripped From Underexcitation

SINGLE-PHASING GENERATOR AND UNBALANCED LOADS

Operating a generator that is designed for three phases as a single-phase generator, or on severely unbalanced systems, will cause negative-sequence currents (I_2) in the generator stator. These I_2 currents will induce currents in the rotor and cause hot areas. Generator rotors are designed to have thermal capabilities for both continuous I_2 and short-time $I_2^2 t$ for unbalanced faults as defined in the ANSI C50 standards series. For example, ANSI Standard C50.13-1975 (7) specifies that indirectly (conventionally) cooled cylindrical-rotor machines are required to withstand a continuous I_2 of 10% and a short-time $I_2^2 t$ of 30% (I_2 measured in amperes; t measured in seconds). Direct-cooled rotors have lower values of both continuous I_2 and short-time $I_2^2 t$ as shown in ANSI Standard C50.13-1975 (7). I_2 capabilities for hydrogenerators and generator/motors are given in ANSI Standards C50.12-1982 (11) and in C50.14-1977 (12) for gas turbine generators.

Generator single phasing can be caused by open circuits in the generator, buses, unit transformers, or generator breaker. The open circuits may result from faulty conductors or connections or failure to reconnect all three-phase circuits after opening the circuits for maintenance or repairs. One or two stuck poles on a generator breaker can single phase a generator. One stuck pole can single phase a generator that is connected to the system through a delta-wye unit transformer.

Relays can be used to alarm or trip for excessive I_2 . Whether relays are used or not, operators should be made aware of the damage that can be caused by excessively unbalanced loads or a zero current reading on one or two generator ammeters. Untransposed transmission lines and unbalanced loads can both contribute to unbalanced three-phase currents on the machine. The percent I_2 can be calculated from the three phase currents by using symmetrical components methods, or curves of the type shown in IEEE Standard 67-1972 (10).

OPERATING HYDROGEN SYSTEMS

The turbine generator operating data should be recorded in the form shown in Table 1-3 at least monthly, or more frequently if there are indications of problems with hydrogen systems. Trends can be observed and plotted if desired, and operators can be advised when limits are exceeded or when abnormal changes are experienced.

Hydrogen systems should be operated within the limits of pressure, temperature, purity, and humidity prescribed on the nameplate or in manufacturers' instructions. Operating the generator at higher pressures than required by the capability curves is unnecessary, results in higher hydrogen use, and may blow the hydrogen seals on the shaft. Operating at a too-low hydrogen pressure may cause the generator to overheat because the pressure is too low for the loads shown on the capability curves. Moreover, if the hydrogen pressure is allowed to fall to atmospheric pressure, air may ingress into the generator, thereby creating an explosive mixture (5 to 75% hydrogen in air). Some operators will "bottle" generators to avoid hydrogen loss during load cycling. Hydrogen is shut off at high loads when temperatures are high, and hydrogen pressure will become low at lower loads and lower temperatures. When loads are again increased, the hydrogen pressure will be satisfactory or can be increased to keep within the limits of the capability curves. Operating in this manner eliminates the need for venting and later increasing the hydrogen supply.

The hydrogen temperatures should be carefully controlled to prevent damage to the generators and to minimize differential expansion between rotor windings and forgings and between stator windings and core. Cold-hydrogen (-gas) temperatures are controlled by regulation of the cooling water to the hydrogen coolers. ANSI Standard C50.13-1977 (7) prescribes a maximum cold-gas temperature of 46°C for indirectly cooled machines rated at 30 psig, and 45 to 50°C for directly cooled generators rated at 30, 45, 60, and 75 psig. The minimum hydrogen temperature is also stated by some manufacturers to prevent mechanical stresses caused by operating the rotor forging at rated speed but too cold a temperature. Hot-gas temperature limits are defined by certain manufacturers to prevent generator damage and to alert the operator to hydrogen cooler problems, such as dirty cooler tubes or air-locked waterside (inadequate venting). Some machines with multiple hydrogen ratings are not operated at top hydrogen pressure if the machine is operating at high power factor. This practice has the advantage of reducing windage losses and reducing hydrogen consumption (loss of hydrogen through the seals and into the oil system).

The hydrogen purity must be maintained at a level high enough to avoid the possibility of a hydrogen explosion, as noted above. Most systems are set to alarm when the purity decreases to 90%. At that point, the generator casing should be

Table 1.3 Turbine Generator Operating Data

		Unit Number		Unit Number	
		High Pressure	Low Pressure	High Pressure	Low Pressure
Section I					
1.	Maximum MW				
2.	Date of maximum MW				
3.	Time of maximum MW				
4.	Generator seal system operating hours				
5.	Hydrogen consumption* (ft ³)				
Date and time the following typical full-load readings were taken.					
Section II					
1.	Load		(MW)		
2.	Reactive load		(kVAR)		
3.	H ₂ purity, casing		(%)		
4.	Generator gas moisture		(# H ₂ O/# H ₂)		
5.	Seal-oil temperature to seals		(°F)		
6.	Fan differential pressure		(inches of H ₂ O)		
7.	Gas pressure		(psig)		
8.	Seal-oil pressure, turbine end		(psig)		
9.	Seal-oil pressure, collector end		(psig)		
10.	Gas temperature to H ₂ coolers		(°C)		
11.	Gas temperature from H ₂ coolers		(°C)		
12.	Water temperature to H ₂ coolers		(°C)		
13.	Water temperature from H ₂ coolers		(°C)		
14.	Field temperature		(°C)		
15.	Maximum stator RTD** temperature		(°C)		
16.	Recorder point number				
For liquid-cooled generators:					
17.	Stator (water) (oil) inlet temperature		(°C)		
18.	Stator (water) (oil) outlet temperature		(°C)		
19.	Water temperature to stator (water) (oil) coolers		(°C)		
20.	Water temperature from stator (water) (oil) coolers		(°C)		
21.	Maximum end-shield temperature		(°C)		

*Adjusted for 14.7 psia at 70°F (standard cubic feet).

**RTD = Resistance temperature detector.

purged by adding fresh hydrogen to bring the purity above 90%. A decrease in purity may indicate impure makeup hydrogen, problems in the detrain-ing system, improper operation of scavenging-type systems, or improper operation of seal-oil vacuum-degassing-type systems. On the other hand, regular decreases of hydrogen purity are normal for certain brands of generator because the manufacturer makes no provisions for removing contaminants from the hydrogen. For the latter generators, periodic purging with fresh hydrogen is the only way to keep the purity above 90%.

The hydrogen must be kept dry to prevent corrosion and possible failure of austenitic (18 Mn = 5 Cr) rotor retaining rings. These nonmagnetic retaining rings have been supplied on most generators built since 1960. Before 1960, most retaining rings were carbon steel. Dry hydrogen is also required to prevent rusting of generator internal steel parts. The rust may be picked up by the

hydrogen and laid out on the stator or rotor wind-ings. Dry hydrogen is essential in certain genera-tors where fluxes used in manufactured hydrogen coolers can combine with moisture. The resulting material can be transported to the stator windings and cause electrical faults.

Moisture can enter the generator from wet makeup hydrogen, water leaks from hydrogen coolers or the stator water system, and water in the hydrogen seal-oil system that will carry over to the generator hydrogen. In the latter case, water comes from such remote sources as a turbine steam leak into the turbine bearing oil, which eventually becomes seal oil. The hydrogen dew point should be checked at least once per month and should be less than -1°C. Fresh hydrogen has a maximum dew point of -65°C. One manufacturer sets a relative humidity of 80% or less as an accept-able limit based on the temperature of the retain-ing rings and the dew point of the surrounding gas.

The same manufacturer gives 7°C as a maximum dew point at machine hydrogen pressure and when the machine is operating.

Certain generator manufacturers furnish hydrogen dryers to remove moisture from the gas. A portion of the hydrogen flow is routed through the dryer where a dessicant extracts the moisture. The accumulated moisture is then removed by heat cycling the dryer and dessicant or by replacing the saturated dessicant.

Other manufacturers have concluded that hydrogen dryers are not required provided that the makeup hydrogen is dry. One manufacturer does not furnish hydrogen dryers on new machines and has recommended that dryers provided on generators built before 1960 be removed from service.

During outages, moisture problems can be avoided by several methods, such as maintaining positive hydrogen pressure at a reduced pressure level, maintaining a slight positive pressure of dry air or dry nitrogen, using dehumidifiers or safe electric heaters inside the generator. Section 1.12 provides suggestions on how to keep a generator dry.

OPERATING STATOR WATER SYSTEMS

Data recorded on forms (Table 1-3) should be obtained and checked monthly for developing trends and to ensure that operators are observing critical limits.

Water pressures, temperatures, and conductivity must be closely watched to prevent generator damage, as noted in Section 1.10. Low pressure will cause inadequate flow in the stator windings and failures from overheating. High temperatures of inlet water can result in boiling outlet water, insufficient heat removal from the stator copper, and insulation damage with possible failure. Stator water coolers must be operated to provide stator water that is within high and low limits. These coolers also limit the rate of temperature change of the stator water. To avoid thermal damage to generator components, the manufacturer's recommendation for this limit should be observed.

Stator water conductivity is kept as low as possible, in the range of 0.5 micromhos/cm or less, to prevent current flow through the Teflon hoses to ground. Deionizers continuously polish about 10% of the stator water flow to keep the conductivity at low values. If the resins become exhausted or are "poisoned" by CO₂ entry during gassing

procedures via a stator system leak, the conductivity can increase to unsafe levels and cause a failure through the Teflon hoses.

Stator water systems should be checked for excessive hydrogen leakage into the system, which indicates a hole in the stator copper, hoses, or water piping. Hydrogen or an explosive mixture will appear at the vent from the stator water storage tank. In addition, the stator water conductivity will increase due to hydrogen carrying dirt or other contaminants into the stator water system.

Stator water systems have filters to trap small particles, and the differential pressures across these must be checked for indications of blockage. Certain filter material may disintegrate and plug the filters and strainers.

OPERATING EXCITATION SYSTEMS

Excitation systems are controlled either automatically by AVR's or manually to provide the voltage and reactive (VARs) required by the connected load or system. System analysts and operators normally set the system voltage schedule. The generator operator is responsible for ensuring that the machine is loaded within the voltage and reactive limits defined by standards and capability curves. Overexciting or underexciting a generator during operation of the voltage regulators must be avoided.

OPERATING VOLTAGE REGULATORS

Generator voltage levels are set either manually or by AVR's. Provisions are made to transfer back and forth using null meters between manual and automatic regulation, as required to keep the generator in service in case of problems with either regulator. The operator must be aware that AVR's will maintain a set voltage regardless of frequency; if the generator's speed is allowed to decrease, there is the risk of damage to both the generator and connected transformers from too high a level of volts per hertz. Some excitation systems may have relays or control functions to protect the unit from excessive volts per hertz.

Normal practice is to keep AVR's in service whenever possible for the following reasons:

- They maximize transient and steady-state stability limits.

- They provide protection from over- and underexcitation. (Most excitation systems do not provide this protection when operated manually.)

When regulating voltage manually, there is the risk of both over- and underexcitation from improper operation. Most companies require that AVR's be used when they are available and that voltage be regulated manually only when the AVR's are not available. As noted above, avoid both over-excited and underexcited operation when voltage is being regulated manually.

LIFE CYCLE

Many generators (and units) will experience a life cycle starting with base loading, then cycling duty, then peaking duty, and finally shutdown. The various stages are caused by efficiencies and costs determined by the prime movers and not normally by any changes in the generators. Operation and maintenance personnel should be aware of the concerns related to changing unit duty.

Base loading may be the least severe duty, other than shutdown, because the generator is not subjected to increases and decreases of load and the associated changes in temperature and in forces on the windings. Ironically, base loading normally occurs in the early life of a unit, when equipment is new, reliable, and efficient; cycling duty usually develops as a unit becomes older and less economical to operate than the rest of the system. However, cycling duty sometimes develops even for newer units; for example, some system operators on new machines have problems getting generation low enough for night or weekend load requirements without removing units from service.

Cycling duty is usually more detrimental to equipment than base loading because of changes in load, forces on the windings, and temperatures. These changes subject the generator to a number of problems. The stator insulation on most generators built before 1960 is an asphalt-mica compound, which has a tendency to break down and crack as it ages. This is referred to as "girth cracking." Cycling accelerates the cracking because of differential thermal expansion (during starting) between the insulation, the copper conductor, and the core iron. The more frequently the generator is started, the greater the likelihood and severity of the girth cracking. The physical strength of the insulation may also have deteriorated, so that sudden fault conditions may impose winding stresses

that will cause stator-winding failures. Ground faults in the windings may seriously damage the stator core and may require a long outage to repair. It may be necessary to rewind these older stators.

Generators built since the late 1950s normally have synthetic resin and mica insulation, which is physically stronger and does not deteriorate as rapidly as asphalt-mica insulation systems. Stators with each type of insulation system will require more frequent inspections during cycling and peaking duty to permit winding maintenance.

Operators can minimize temperature changes and the resultant girth cracking by carefully adjusting cooling-water flows or temperatures. Hydrogen pressures can be regulated by "bottling" the generator at higher loads and temperatures; this step allows hydrogen pressures to decay (within capability curve limits) when loads are decreased and allows pressures to increase to normal levels again when loads are increased. Unnecessary venting and makeup of hydrogen is thereby avoided. Most generator manufacturers recommend that the stators of generators used in cyclic service be rewound using modern insulation compounds that prevent girth cracking.

Older generators with spindle-mounted retaining rings for the coil-end turns can also develop fatigue cracks in the field winding. Plastic deformation of the retaining rings occurs during starting because of the centrifugal expansion of the end turn relative to the field body. Again, the likelihood of failure increases with the number of generator starts. Eventually these mechanical and electrical stresses will damage the insulation and cause the coil and turns to break. Modifications to retaining rings are available to help prevent this fatigue cracking.

The two large-generator manufacturers in the United States have recently advised utilities to replace 18 Mn-5 Cr retaining rings with 18 Mn-18 Cr retaining rings. The latter are less susceptible to stress corrosion cracking, which can grow under the influence of cyclic operation.

The rotor experiences a major stress cycle each time the unit is started; load-cycle failure is therefore a concern. To determine suitability for continued service, whether baseload or cycling duty, manufacturers recommend nondestructive tests (NDTs) for all pre-1959 rotors and rotors manufactured from non-vacuum-degassed forgings. Boresonic, peripheral sonic, magnetic particle, and visual inspections will yield data that may call for overbore, bottle bore, and/or honing to remove

tracks or cracks in the bore. In addition, trepan samples may be obtained from the forging to obtain metallurgical data. Based on these data, manufacturers may recommend a limit of load cycles, rotor prewarming before reaching full speed, or scrapping of the rotor as unsafe to operate.

Older generators may require several hours of prewarming to obtain the proper rotor temperature at a safe rate of temperature rise. Low brittle transition temperatures call for prewarming if the rotor forging temperature is too low. The rotor of a single generator unit can be prewarmed by applying appropriate field excitation current at about 70% of rated speed during start-up and carefully monitoring the rate of temperature rise. For cross-compound units, apply the field current at roll-off from turning gear to compound the two generators; then adjust the field current on the prewarm rotor to attain an acceptable rate of rotor temperature rise. The generator should be rotating during prewarming to prevent hot spots in the rotor winding and on the collector rings.

Rotors built since 1960 using vacuum-degassed forgings are generally not of major concern for cycling duty, but each generator stator and rotor must be carefully checked before entering cycling or peaking duty. If prewarming is required, weekend cycling may be limited, because the rotor may be too cold for fast starts after a weekend outage.

In some generators built before 1986, the shifting of rotor bars during turning-gear operation creates copper dust in the generator field. This dust can damage the generator during cycling duty. As turning-gear operation increases with cycling service, the probability of field shorting increases. There are four ways to reduce the likelihood of this problem:

- Minimize turning-gear operation
- Remove the wedges and vacuum the coils.
- Machine O-ring grooves in the creepage blocks to reduce dust migration.
- Rewind the field and incorporate separators between the layers of each turn.

In addition to these steps, more frequent visual inspection and testing may be recommended for cycled generators. Updated instrumentation to monitor turbine generator operating conditions may include the installation of additional thermocouples to track metal temperatures and a modern microprocessor-based turbine generator control system to automate startup and synchronization of the unit. Newer units typically already have such control systems.

Peaking duty is the most severe type of operation, particularly for units initially designed for base loading. Peaking-duty units normally are in service during daytime peak loads and are shut down during nighttime off-peak periods. The generator may be subjected to maximum loads for a few hours morning and evening—with minimum loads between peak hours—then shut down after evening peaks. Such drastic changes in load can be very detrimental to generator components unless operators limit temperature levels and swings by judicious use of cooling-water controls and bottling techniques to preserve heat in the machine.

The final stages of generator life are standby, shutdown, retirement, and demolition.

LIFE EXTENSION

Comprehensive guidelines for extending power plant life will help utilities establish and implement life extension programs. Such guidelines have been issued in EPRI report CS-4778 (13). These guidelines discuss the important issues that a utility is likely to consider during the initiation and ongoing development of a plant life extension program. An example illustrating the determination of the remaining life of generator stator insulation, generator rotor, and retaining rings is presented in the guidelines.

1.12 MAINTENANCE

INSPECTION AND MAINTENANCE PROGRAMS

Programs consisting of regular inspections and maintenance of generators will usually prevent in-service failures and costly repairs. Most manufacturers of large generators recommend rotor removal, visual inspection, and electrical tests on a three- to five-year schedule. Some utilities believe this schedule calls for too many inspections, particularly given the possibility of damage and contamination to the rotor, stator core, and windings during rotor removal.

The other extreme is to run a generator until it fails, which may have a major impact on the utility's generating capacity for many months.

An intermediate approach used by certain utilities is to tailor the inspection and maintenance program to the types of generators on the utility system. Troublesome machines with a history of failures or with stator or rotor problems are

inspected more frequently than those machines with a good operating history. For example, older turbine generators with stator cores 150 in. or longer and asphalt-mica-insulated stator windings may be inspected every five years or more frequently because of the tape separation and girth-crack problems with the stator windings. Asphalt-mica generators with stator cores less than 150 in. may be inspected on a six- to eight-year schedule.

Synthetic-resin-insulated (epoxy or polyester) generators have different problems and may require a different inspection and maintenance schedule. Turbine generators tend to require frequent inspections for fretting of the end windings, which may require retightening and treatment with resins. In addition, the coils may become loose in the slots, thereby requiring rewedging. Hydraulic turbine generators with synthetic-resin coils have experienced major problems with these hard coils. When the coils become loose in the slots, they result in slot discharge and wear away the groundwall insulation. These machines require frequent inspections and rewedging.

Record keeping is an essential part of a generator maintenance program to establish each machine's history, to determine trends and deterioration, to record insulation resistance values, and to plan future inspections and maintenance.

The generator maintenance program shown below may help prevent in-service failures of steam or gas turbine generators. This program can be modified to apply to hydraulic turbine generators and generator/motors:

- First inspection after 1 year of service.
- Next inspection in 3 to 5 years, depending on the conditions noted at the first inspection.
- For older asphalt machines, establishment of trends and inspection intervals based on this experience:
 - Every 5 years for troublesome, long-core machines (core lengths 150 in. or longer).
 - Every 8 to 10 years for less-troublesome, short-core machines (core lengths less than 150 in.).
- Inspection of synthetic-resin machines every 8 to 10 years for core lengths less than 150 in.
- Inspection of synthetic-resin machines every 3 to 5 years for core lengths 150 in. or longer.
- Immediate inspections after close-in faults, motoring, or indications of problems.

- Visual inspections by trained generator specialists to determine generator condition. If the dielectric integrity of stator insulation is suspect, apply a high-potential test on each phase-to-ground with the other two phases grounded, preceded, and followed by insulation resistance tests to ground.
- Maintenance of windings during inspections.
- Insulation resistance tests during annual outages.
- Maintenance of generators during inspections or as required from operation monitoring of
 - Hydrogen coolers.
 - Hydrogen seals.
 - Bearing temperatures.
 - Winding temperatures.
 - Vibration.
 - Hydrogen use.
 - Field grounds.
 - Stator water conductivity.
 - Core monitor.
 - Water and oil leakage detectors.
 - Hydrogen dew point.
 - Hydrogen purity.
- Monitoring of and alarms (when necessary) for critical parameters.
- Monthly reports of critical parameters.

FORMS AND CHECKLISTS

Forms that may be used as checklists during maintenance and inspections are included in Appendix A to this volume. One of these forms, the generator equipment annual maintenance data form, is a generic checklist that can be used during annual inspection of the generator, exciter, and auxiliary systems. Selections of certain sections will be required for application of the checklist to specific generators and auxiliaries. The motor, generator, synchronous condenser trouble report, which is included in Appendix A, lists details to investigate following a failure.

GENERATOR EXTERNAL CONNECTIONS

Connections external to the generator should be checked at least once per year for evidence of heating, corrosion, and loose or broken bolts. The line terminals and bus or isolated-phase bus

connections should be checked at all joints and links, from the generator to the unit transformer. The neutral terminal connections and the connections to the neutral grounding device should also be checked. On isolated-phase buses, the external shunts, shields, joints, and insulation should be checked for heating, open shunts, and deteriorated insulation.

Bus materials may be copper, aluminum, or aluminum alloys. These materials may be plated with silver or cadmium. Manufacturers' instructions for connections should be closely observed; they provide detailed information on:

- Surface preparation and types of cleaning abrasives
- Anti-oxidant pastes or materials
- Bolt materials (aluminum, stainless steel, Duroz, or Everdur)
- Washer material and type (flat, lock, Belleville)
- Bolt torques, procedures, and sequence of tightening

PROCEDURES FOR DRYING ELECTRICAL INSULATION

Care must be exercised to avoid overheating the windings and damaging the insulation. One or several drying methods may be used.

External Methods

- Space heaters.
 - Electric.
 - Steam.
 - Hot water.
- Heat lamps.
 - Incandescent lamps.
 - Infrared lamps. (Caution: Avoid overheating insulation. Overheating may occur well inside the insulation surface.)
- Dehumidifiers.
- Desiccants.
- Hot water in air or hydrogen coolers.
- Hot water in stator water coolers.
- Core test (ring test).
- Oven (including construction of a temporary enclosure around the machine).
- Forced hot air.
- Dry air or dry nitrogen.
- Vacuum treatment.
- Wet-dry vacuum (shop vacuum cleaner).

Internal Circulating Current (Specify current and temperature limits.) It is essential to use low values of currents initially to limit the rate of temperature rise 10°C per hour, to establish the thermal lag in temperature measurement, and to avoid hot spots and possible flashing of water into steam and consequent insulation damage.

- Dc.
 - Welders, parallel if necessary—transformer type or motor or engine driven.
 - Exciter (motor-generator set or external excitation supply, such as a reserve exciter).
- Ac. (Use low voltage.)
 - Station service system (short field of synchronous machines).
- Shorting windings.
 - Ac generator stators, short stator. (Excite field at low current. Observe stator current and RTDs. Drive generator.)
 - Dc generators, short armature. (Separately excite shunt field. Observe current in armature circuit. Drive generator.)

PROCEDURES FOR DRYING GENERATOR ROTOR WINDINGS

The following procedures are primarily for a turbine generator rotor. Modifications can be made to use similar procedures for other types of generator rotors.

It is essential that rotors with 18 manganese-5 chromium (18-5) retaining rings always be protected from moisture because of the stress corrosion cracking problems associated with this type of retaining ring.

The insulation resistance of the ground insulation for a generator field winding may decrease to a level that makes the field unsuitable for service. The minimum value of the insulation resistance (Megger reading) is 1 MΩ/kV of field rating plus 1 MΩ. For example, a 500-V field would have a minimum Megger reading of 1.5 MΩ.

Insulation resistance on a field is measured with a 500-V Megger reading to prevent overstressing the insulation. The field winding must be grounded prior to taking a reading in order to discharge the winding capacitance to ground. Remove the ground before taking the readings. The reading taken at 1 min should then meet the minimum values noted above for the rating of the field. A reading taken at 1 min is divided into the 10-min reading to give a polarization index (PI). A

motor-driven or electronic Megger is required for a good PI test. The minimum PI for a field in good, dry condition is normally 1.2. See Volume 6, *Motors*, for a detailed discussion of the polarization index.

The field insulation resistance may drop to unserviceable levels for a number of reasons:

- General deterioration of the ground insulation from heat or age
- Carbon dust, fly ash, or moisture around the collector-ring insulation to the shaft
- Faults or contaminants in the field windings
- Moisture in the field windings

Low Megger readings may be obtained when the brushes are in contact with the collector rings. The first step in checking is to lift all brushes and determine whether the brush rigging and attached cables—or the collector rings and field windings—are responsible for the low readings.

If the brush rigging or cables are the cause of the low readings, the rigging, cables, instrumentation leads, and rheostat must be checked and the reading improved to the minimum value described above.

If the field has the low reading, the next step is to clean and dry the collector-ring insulation. It is important not to slosh solvents around this area but rather to vacuum, blow with dry air (maximum 30 psig), and then wipe with solvent-dampened cloths.

If the low Megger reading persists, the cause may be moisture. Units out of service for long outages may well have low readings caused by soaking up moisture. In the past, several methods have successfully removed the moisture and improved the Megger reading to a safe level:

- Bleed dry air or dry nitrogen through the generator from an opening in the bottom of the generator; vent it out the top. Personnel must not enter the generator if dry nitrogen is used.
- Blow hot, dry air in one end of the generator and draw air from the opposite end with an air evacuator.
- Put dehumidifiers inside the generator and drain water to the outside. Except for the drain, the generator is closed up.
- Circulate stator water in water-cooled generators. The friction in the stator system warms the entire machine. The generator

should be closed up, except for a modest amount of venting. Also, the raw water to the stator water coolers should be closed off, as well as water to the hydrogen coolers. Note that certain manufacturers may not agree to operation of the stator water system without hydrogen in the generator at a pressure higher than the stator water pressure.

- Put an electric space heater inside the generator and use a small amount of venting. Care in selecting the electric heaters is essential to prevent overheating and setting the winding on fire.
- Put heat in the field from a dc source (such as a dc welder) to the collector rings. Care must be exercised to prevent damage to the collector rings or field windings. Copper clamps must be fabricated to completely surround each polarity of ring (or rings). The stinger lead from the welder is then connected by bolted connectors to one polarity clamp or clamps and the ground lead to the other polarity of ring clamp(s). One should not connect the welder between one ring and ground because the field winding might not be effectively dried out and the forging could be destroyed by the high welder currents required. Further information and precautions about this method follow:
 - The field-winding temperature must be closely monitored to prevent overheating of the winding and insulation. Low values of current should be used initially and the thermal time lag noted to avoid overheating the windings and insulation.
 - Accurate readings of welder volts and amperes are required to calculate field resistance. A shunt and millivoltmeter are required for reading amperes.
 - A curve of field resistance versus temperature is plotted for conversion of resistance values to temperature. Factory values of field resistance at 25°C are normally available. This factory value provides one point on a straight line plot. The second point is calculated from the formula for copper resistance change with absolute temperature:

$$\frac{R_1}{R_2} = \frac{234.5 + T_1}{234.5 + T_2} \quad (\text{Eq. 1-2})$$

Where:

R_1 = resistance at temperature T_1

R_2 = resistance at temperature T_2

T_1 and T_2 = temperature in degrees Celsius

Usually, 100°C is used for the calculation of resistance for the second point. Figure 1-24 is a typical curve.

Note: If a factory resistance value is not available, a value can be obtained with a Kelvin or Wheatstone bridge or a digital ohmmeter connected to the collector rings with the welder disconnected. Another method is to read the volts and amperes from the welder as soon as it is applied and then calculate the field resistance. The temperature accompanying these resistance values can be obtained from the stator resistance temperature detectors if the field is in the stator, or from a nonmercury thermometer on the forging if the field is outside the stator.

- Apply low amperes from the welder initially until the effect on temperature is determined. For example, apply 100 A to an 800-A rated field. The current then must be adjusted as necessary to limit the rate of temperature rise to 10°C/h. The maximum field temperature for dryout is 80°C. This procedure precludes flashing trapped water into steam and damaging the insulation. Plot a curve of time versus temperature to project when 80°C will be attained and the current required to reach 80°C.
- The welder must be rated continuously for currents selected to prevent welder burnup. Also, the welder dc must be ungrounded both externally and internally.
- Temperatures and Megger readings should be checked hourly until trends are established; then longer periods can be used between checks. The Megger reading will usually drop to a lower value initially as the temperature is raised. It will then start to increase. Megger readings should be corrected to a standard temperature in order to establish trends. Figure 1-25 has temperature coefficients for conversion of insulation resistance to 40°C. The corrected Megger readings should be plotted versus time to determine when satisfactory values for service are obtained.
- Dryout of field windings requires days (or weeks, in some cases).

- Caution: If the field is outside the generator, and welder current is applied, the area around the field must be roped off at a safe distance from the field forging. The reason is that the strong magnetic field will rip magnetic tools, steel chairs, or other magnetic materials from nearby personnel, possibly causing injury.

MAINTENANCE OF DC EXCITERS AND GENERATOR COLLECTOR RINGS

Good generator exciter performance is essential to the operation of all power plants. The loss of an exciter will shut down the entire unit. Synchronous condensers and hydrogenerators are similarly dependent upon exciters.

Although it is not expected that all maintenance problems on exciters can be eliminated, an understanding of these problems and sound preventive maintenance practices can keep trouble to a minimum. The commutation performance chart (Table 1-4) summarizes types of commutator troubles and their causes.

Commutator film is a composition of copper oxide, carbon, and various materials present in the surrounding atmosphere. In addition, invisible layers of water vapor adhere to the collecting surfaces of the commutators. All these constituents are important in forming a good commutating film for long brush life and minimum commutator wear.

Formation of film is primarily caused by vaporization of metal from the commutator. This metal oxidizes and is mechanically rubbed back onto the commutator by the brushes. Moisture from the surrounding atmosphere combines with the copper oxide and carbon from the brushes to form a smooth film for the brushes to ride on. The condition of this film is affected by the type of brush, treatment of the carbon materials, and atmospheric conditions. Directly connected hydrogen-cooled exciters are used in synchronous condensers to eliminate any need for shaft sealing. Depending on the dryness of the hydrogen, it may be necessary to use special brushes for these exciters.

A commutator film may be destroyed by a number of conditions. Acid and base contaminants, dust, and oils will react with brush and collector surfaces to destroy the film. Changes in humidity will also affect the film by causing changes in contact drop and brush friction.

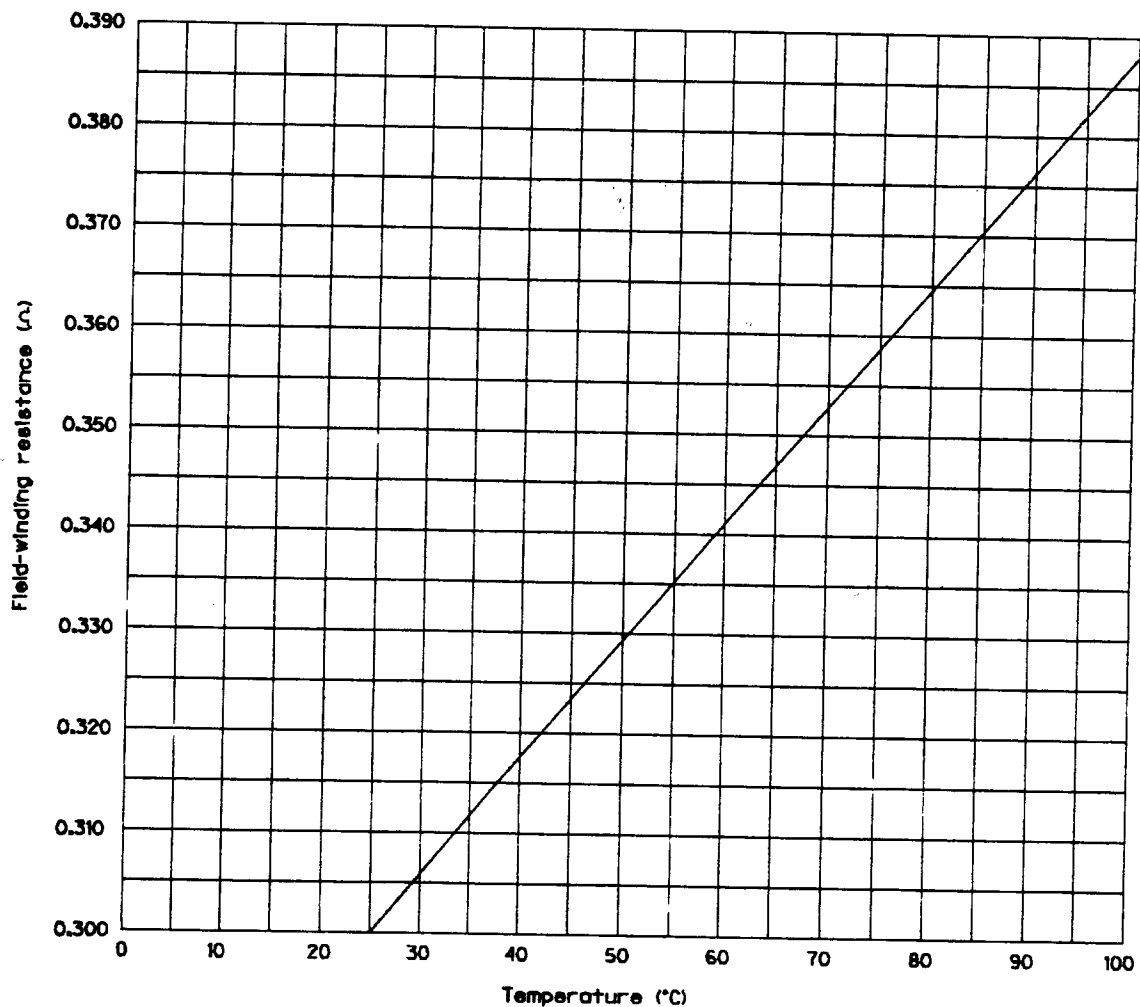


Figure 1-24 Typical Resistance Versus Temperature for a Generator Field

Chemical contamination is usually harmful to the film because it causes formation of materials other than copper oxide on the commutator.

Dust has an abrasive action that cuts the film, while other types of suspended particles react with the vaporized copper to form nonconductive films.

Oil vapors introduce an insulating surface on the commutator. Also, oil vapors prevent bonding of the film to the copper surfaces; lack of bonding promotes rapid metal transfer and eventually damages the commutator.

A number of conditions are necessary to establish a good film once a commutator has been resurfaced. The commutator should be as smooth as possible. Brushes should be fitted to the commutator and the correct pressure set on each brush. Generally, prefitted or fluted brushes do not require any shaping before installation. The

machine should be electrically adjusted to give optimal performance.

In some cases, even when these conditions are met, a satisfactory film may not be attained because of atmospheric conditions. Special brushes may sometimes be used to develop a greater and quicker deposit of film.

Current density is another important factor in forming a satisfactory film. Low current densities will allow vaporized copper to be embedded in the brush face and eventually damage the commutator. Current densities should be kept high enough to limit friction and allow the vaporization of the unoxidized copper deposited in the brush face.

Where high-resistance spots on the commutator surface cause a nonuniform film, a clean canvas cloth may be used to wipe the commutator to give a more uniform film. The canvas cloth should be

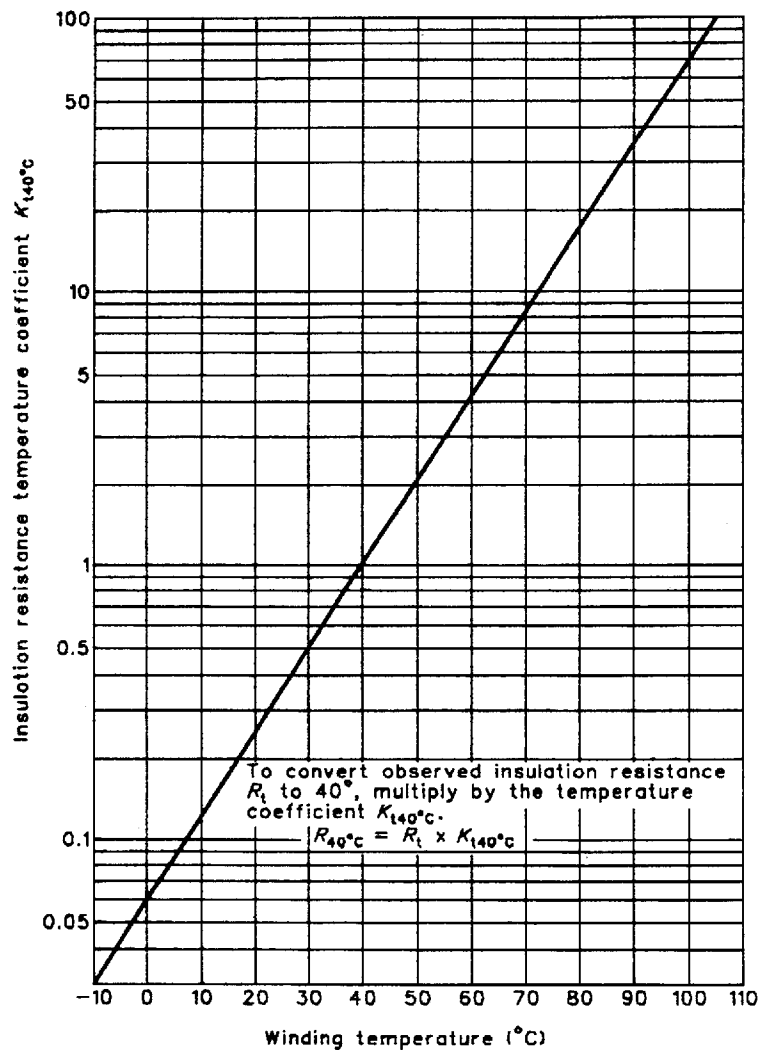


Figure 1-25 An Example of Insulation Resistance Variation With Temperature

stretched over a board that can be properly supported and moved across the commutator surface. This method will not destroy the film essential to good commutation. The canvas cloth should be an untreated type—that is, without chemical or rodent-proofing treatments.

Colors of the films that form on commutators vary from a light tan to black, depending on the application method. The color of the film is not important as long as brush and commutator wear is satisfactory and brush sparking does not occur.

- **Allowable Vibration Levels** One of the basic causes of short brush life and damaged commutators is excessive vibration. Two types of vibration that occur between brushes and commutators are chatter and vibration caused by eccentricity.

Chatter is caused by frictional forces between the contact surface and the face of the brush. High-frequency vibrations may be set up just as a piece of chalk squeaks as it is drawn across a blackboard. This chatter may cause breakage of the brushes or damage to the brush holders. In some cases, chatter may be relieved by increasing the brush pressure.

The vibration decreases the contact between brushes and commutator. This reduced contact causes increased arcing between brush and commutator, usually resulting in a rough commutator surface. Once the commutator begins to get rough, the condition gets progressively worse until corrections are made.

Definite allowable vibration limits for brushes are difficult to establish because

Table 1.4 Commutation Performance Chart

Causes	Basic Problems										
	Electrical Sparkling	Brush Wear	Mechanical Brush Wear	Chatter	Selective Action	Threading	Grooving	Drag or Feathering	Slot Pattern	Pitch Pattern	High Film Resistance
Brushes											
Electric											
Good commutation			X	X		X					
Poor commutation	X	X		X	X	X			X		
Mixed brushes	X			X	X	X	X		X		
Machine Design											
Brush holder											
stability				X							
Electric design	X	X								X	
Mechanical design	X		X						X		X
Machine Assembly											
Circumferential											
brush space	X										
Radial brush									X		
space			X	X							
Uneven brush											
pressure	X				X	X		X	X		
Light brush											
pressure	X	X			X	X		X	X	X	
Heavy brush											
pressure			X				X				
Alignment		X		X							
Rough bearings		X		X						X	
Balance		X		X						X	
Bent shaft		X		X						X	
Induced vibration		X		X						X	
Uneven CP* gaps	X	X			X				X		
Uneven MP* gaps											
High side mica	X	X	X	X						X	
Poor armature											
connections	X	X							X	X	
Shorted CP*	X	X							X		
Shorted MP*		X							X		
Loose commutator	X	X	X							X	
Elec. adj.	X	X			X				X		
Atmosphere											
Low humidity	X	X	X	X							
High humidity		X	X			X					
Abrasive dust			X				X				X
Oil				X		X		X			
Gas—acid	X	X		X	X	X		X	X		X
Gas—base	X	X		X	X	X		X	X		X
Silicone		X						X	X		X
Application											
Light load				X		X					
Overload	X	X			X				X		
Regulator	X									X	
Control	X								X		

*CP = commutating pole; MP = main pole.

limits change for each variable such as speed, load, and brush pressure. Certain eccentricity values may serve as a good guide in preventing troubles. For a 3600-rpm exciter, eccentricity should not exceed 1.5 mils. For exciters with speeds of 1800, 1200, and 900 rpm, eccentricity values should not exceed 2.5, 5, and 6 mils, respectively.

One method of establishing allowable vibration levels on a particular machine is to keep accurate records of vibration readings. As vibration levels increase, the operator

should watch for trouble signs. Once vibration levels reach a point at which damage begins to occur, vibration limits can be established.

- **Brush Life** The best method of establishing what constitutes good brush life for a machine is to compare the brush life to that of similar machines operating under similar conditions. Brush life is affected by the surrounding atmosphere, speed of the contact surface, and current density; it is difficult,

therefore, to give definite values for good brush life to cover a number of machines.

Brush life should not be considered the most important factor in commutation. If the commutator shows no threading, grooving, or harmful markings, then the brush performance should be considered satisfactory. It would be unwise to sacrifice performance merely to use a brush with a longer brush life.

Up-to-date brush records may be important in avoiding trouble on a commutator. A record of brush wear in mils per 1000 h of brush service should be used to judge performance. A significant increase in brush wear is usually a sign that some mechanical or electrical condition has changed and may cause commutator damage.

- **Sparking** No company will guarantee sparkless commutation on its equipment. Sparking is not necessarily harmful unless it becomes excessive. In fact, it is an important factor in forming a film on the commutator.

The effect of sparking is to vaporize the copper from the commutator and brush face. This copper is oxidized and rubbed back on the commutator surface by the brushes. When sparking becomes excessive, copper is deposited on the brush face that is not oxidized and rubbed back onto the commutator surface. The sliding action of the brush on the commutator causes the copper that has been deposited in the brush face to become work hardened. This copper then acts as a cutting tool and threads the commutator.

- **Preventive Maintenance** Many commutator problems will not occur if exciters are routinely maintained. Routine exciter maintenance requires care to see that proper brush pressure is held, that the brushes are operating at adequate current density, that there is no undue brush chatter or vibration, and that the machine is clean. When signs of trouble appear despite proper routine maintenance, nonroutine preventive maintenance must be undertaken to prevent commutator troubles that may result in the loss of the generator or synchronous condenser and/or involve a major commutator repair.

It is necessary to spot these troubles at their inception; once they start, they progressively become worse. Because each trouble may result from several causes, the causes and troubles have been tabulated in Table 1-4. This table will aid in diagnosing commutation difficulties.

■ *Routine Procedures*

- **Brush Pressure** Generally, 3.5 psi is the recommended brush pressure for exciters with trailing-type brush holders. The upper and lower limits are 4 and 3 psi, respectively. For exciters with reaction or leading-type brush holders, the pressure should be increased to 5.5 or 6 psi. The cross-sectional area of the brush—rather than its contact-surface area—should always be used to determine brush pressure. The use of the contact area for this purpose has been recommended in some instruction books, but this approach is not desirable. Instead, the recommended 3.5 psi should be determined by dividing the number of pounds of pull required to free the brush from the commutator by the cross-sectional area of the brush.

A spring scale can be used to measure brush pressures. One end of the scale should be attached to the shunt lead of the brush. Care should be taken to ensure that the pull on the scale is along the axis of the brush's travel in the holder. Pulling the scale at an angle to this axis may bind the brush in the holder, thus causing an erroneous reading of the true brush pressure. After checking a number of brushes with the scale, a maintenance worker may be able to set the remaining brushes by feel.

Correct brush pressures must be maintained to avoid commutator damage and shortened brush life. Light brush pressures may cause threading, sparking, electrical brush wear, and other types of damage to the commutator. Heavy brush pressures may cause mechanical brush wear or grooving of the commutator.

It is important that each brush on an exciter be set at the same pressure. Unequal brush pressures will cause some brushes to carry more load than others, and this occurrence can also damage the commutator. When spring pressures are adjusted

with or without the brush in place, the weight of the brush—and whether it is above or below the commutator or collector—must be factored into the spring setting.

The condition of the brush holders and springs should also be carefully checked. Damage to either can cause an incorrect pressure to be exerted on the brush, even if the settings are correct.

Periodic checks should be made to ensure that the brushes move freely in the holders. Sometimes brushes bind in the holders or become cocked; brush pressure is thereby reduced, and undue sparking may follow. To avoid this trouble, a few brushes can be lifted each day to see that they slide freely in their holders.

A maintenance schedule should be set up to check brushes, spring pressures, and brush-holder conditions periodically. Workers should not change all the brushes on a commutator at one time because the film may be destroyed. Changing a few brushes each week will give good results.

Constant-pressure brush holders are used on some exciters. While these holders maintain a constant pressure over the usable brush length, brush pressure should be checked periodically to ascertain that the brush-holder springs have not deteriorated.

Brush wear is generally lower on condensers than on generators, so that less frequent checks are necessary for condensers. Whenever possible, however, brushes and holders should be checked for mechanical deterioration.

- *Brush-Current Density* One of the greatest causes of commutator threading is low brush-current density. As brush-current densities drop below 45 A/in.², some of the copper that has transferred to the brush face will not vaporize. The copper in the brush face then becomes work hardened because of the sliding action of the brush, and this embedded copper will act as a cutting tool to thread the commutator.

This process does not preclude threading at current densities above 45 A/in.² or ensure its occurrence at lower values. However, experience indicates that this value can be used as a working base with most machines.

A method of correcting low current densities is to remove tracking rows of brushes. This method should be used with caution, however, because of other factors. Before brushes are lifted as a corrective measure, workers should carefully calculate brush-current densities at both high and low unit loads.

Operating with low currents for short periods of time is not apt to cause threading. If a machine is operating at low brush-current densities more than 50% of the time, however, threading is very likely. Thus, for machines that are subject to cyclic loading, a curve of amperes per square inches versus time should be plotted for a typical 24-h period to determine if corrective action is necessary.

- *Cleanliness* Cleanliness is very important to exciter operation. Oil and dirt may destroy the commutator film, thereby damaging the commutator and possibly deteriorating the insulation.

A dirty machine may overheat because the rate of heat transfer from the windings is reduced by a dust film. Also, excessive carbon dust may cause insulation resistance to become dangerously low.

High-pressure air should not be used to blow dust out of an exciter. This may cause the dust particles to become embedded in the insulation, thus causing the insulation to deteriorate. The use of rags to clean an exciter may also be harmful because the dirt may be rubbed into the insulation instead of being removed. A good vacuum and brush may be the best means of removing dirt from the windings.

■ *Nonroutine Procedures*

- *Coupling Alignment* Exciter couplings should be aligned to within 1.5 to 2 mils. Flexible couplings are used to decrease vibration that must otherwise be transferred from connected generators or driving motors; they are not intended to compensate for misalignment. Because misalignment of the coupling may be magnified on the commutator, it is important to have very close alignment.

One result of misalignment is pitch bar marking. This phenomenon is a roughening of the commutator in a number of

places usually equal to one-half the number of poles in the machine. Once this type of condition appears, its progression can be very rapid. Rapid brush wear may also result from misalignment.

- *Air-Gap Measurement* Good commutation depends on maintaining even air gaps at the main and commutating poles. Air gaps of new machines are set at the factory and generally should not be altered.

When it appears that an improper air gap is causing commutator difficulty, the air gaps can be checked with a feeler gage by one who is familiar with such measurements. It is recommended that air-gap changes be made only by a manufacturer's expert.

- *Brush-Holder Clearance* Brush-holder clearances to exciter commutators range from approximately 75 to 125 mils. Manufacturers' instruction books will give the proper clearance values for their machines.

Any time an adjustment is made to brush holders, the alignment along the axis of the armature should be carefully checked. Alignment of the brushes should be made to within one-half the width of the mica between bars.

- *Change in Brush Grade* If the proper current density cannot be obtained by lifting brushes, if the machine has not been designed for optimal commutating ability, or if surrounding atmospheres are contaminated, it may be desirable to use a different grade of brush. Changes in brush grade should be undertaken only after careful study.

Except in very special cases, the mixing of two or more types of brushes will tend to cause trouble. Each type of brush has distinct characteristics. Mixing them may cause selective action of brushes in loading—that is, some of the brushes may become lightly loaded. Threading will result.

■ *Commutator Repair*

- *When to Dress a Commutator* A number of signs indicate when it is necessary to resurface a commutator—rough surfaces, noise, sparking, rapid brush wear, and even possible fluctuations in load conditions. Many times, however, people will use a stone or sandpaper when it is not necessary.

Commutators may take on a dark color when operating in various atmospheres and with certain types of brushes. This color change is often mistaken as a sign of damage to the commutator or the beginning of damage. Maintenance personnel sometimes use a stone or sandpaper to correct this condition, which actually does more harm than doing nothing at all.

Because wiping with a clean, untreated canvas cloth will remove or lower some high-resistance areas, the frequent use of a clean canvas cloth can greatly help develop and keep a uniform film on the commutator. This practice will also help reduce sparking and, in many cases, is preferable to stoning or sandpapering.

Before resurfacing a commutator by any method, the maintenance supervisor should be very sure that it is necessary. Sometimes a slightly grooved or threaded commutator will be turned or ground when there is actually nothing more serious than a displeasing appearance. Constant smoothing of the commutator surface only wears away the film, thus speeding the wear of the commutator and brushes.

- *Resurfacing Method* The best method of resurfacing a commutator will often depend upon the operator's skills. Both turning and stoning will give a satisfactory job if the operator is highly skilled in this work. The two important objectives are to smooth the surface and make it concentric.

When resurfacing a commutator after the rotor has been removed from its bearings, maintenance personnel should watch for one pitfall. The existing centers may not be the true shaft centers; therefore, it is important to ascertain that the shaft is checked on the existing centers to avoid a surface that would not be concentric with the bearing journals.

Whether using a stone or turning a commutator, a lathe head fixture should always be used. Using a stone that is improperly supported will probably result in an out-of-round commutator surface.

In some cases, the condition of the commutator surface may determine the resurfacing method. On extremely rough surfaces, a cutting tool will probably cut more quickly than a stone. After a surface

has been turned, a fine stone may be used to make the surface smoother.

Use of a hand stone should be restricted. Only a skilled person can do a good job using a hand stone. A person unfamiliar with this type of operation will probably leave the surface in worse condition than before stoning. A hand stone should only be used when it is necessary to keep a piece of equipment on-line until a shut-down is possible.

Sandpaper can be used to polish a commutator surface if the operator has the necessary skill. Using a piece of sandpaper held in the hand will often cause more material to be removed from the bars than from the slot. Chatter, sparking, and excessive heating will result. It is therefore necessary to hold sandpaper in a curved block shaped to fit the surface to avoid crowning the bars. The block should always be supported from a flat surface and moved slowly across the commutator. All loose particles must be removed after using sandpaper.

Sandpaper should be examined before use. Certain types smell like plastic when burned. Such sandpapers contain a bonding material that will adhere to the commutator and form a high-resistance surface. Thus they should not be used. Similarly, emery paper should never be used because of the conducting particles in the paper.

- *Mica Undercutting* After a commutator has been resurfaced, it is usually necessary to undercut the mica. There are two methods: U cutting and V cutting. Both methods are acceptable.

The V cut is easier and faster; however, its effect is less durable than the U cut. The V cut is deeper and therefore decreases the contact surface between brush and commutator, so the U cut is often more desirable.

After undercutting, careful inspection will ensure that no high mica remains to wear away the brushes.

- *Collector-Ring Maintenance* Collector-ring maintenance is somewhat simpler than commutator maintenance because of the difference in structure. Collector rings furnish a continuous surface for brushes to ride on and are subject to fewer types of trouble.

Much of the foregoing information can be applied directly to collector-ring maintenance. Some differences should be pointed out, as well as some additional information that would not apply to exciters.

- *Brush Pressure* Correct brush pressures are just as important for collector rings as for commutators. Light brush pressures will cause sparking, electrical brush wear, and threading of collector rings. Light brush pressures can also cause selective loading of the collector-ring brushes and can result in heavy arcing between the ring and brushes. Constant-pressure brush holders are preferred for collector rings to eliminate this problem. Heavy brush pressures will cause mechanical brush and collector-ring wear.

Normal brush pressures for collector rings range from 1.75 to 2.0 psi of brush cross-sectional area. With high vibration, pressures may be increased to 2.25 psi by maintenance personnel.

- *Polarity Reversal* It is normal for brushes to wear faster on the positive collector rings, whereas the negative rings themselves wear faster than positive rings.

Some instruction books recommend reversing the polarity to collectors to equalize the wear on the rings. The benefits of reversing the polarity of collector rings on large machines will not usually justify the expense and time required to do the work. Therefore, it is not necessary to reverse the polarity on turbine generators. However, because of the more rapid negative-ring wear in hydrogen atmospheres, it is necessary to reverse collector-ring polarities on synchronous condensers periodically.

- *Steel, Brass, and Copper Collector Rings* Although collector rings made of different materials have different characteristics, the same type of maintenance problems occur. Threading and grooving are the two most common problems.

The color of the film on copper and brass rings will be comparable to that on a commutator. Film color on steel rings, which may be carbon steel or tool steel, will vary from steel gray to black. The black color on these steel rings may sometimes cause alarm, but it does not necessarily indicate a bad condition. Again,

film color should not be used as the sole basis for determining performance.

- **Cleanliness** Collector-ring cleanliness is just as important as commutator cleanliness. Foreign materials on the collector-ring surface will destroy film and damage collector rings and brushes. On the newer machines that have forced cooling of collectors, dust, carbon, or any other foreign materials can cause considerable trouble. Any reduction in airflow through the cooling passages may very well cause high temperatures that will damage the rings or brushes. The passages should be inspected and cleaned if necessary when the machines are down for an outage.
- **Danger Signs** One of the first visible signs of impending trouble on collector-ring surfaces is sparking on the negative brushes. Sparking may be caused by vibration or by buildup of nonconductive materials on ring or brushes. As with commutators, a small amount of sparking on collector rings does not necessarily mean that the rings have been damaged. Another condition often observed on collector rings is an outline of the brushes etched on the collector-ring surfaces. This phenomenon, called picturing, can be caused by vibration, brush bounce, poor ring surface condition, weak brush-holder springs, or wrong brush grade. Correction may require balancing, respacing the brush holders circumferentially, resurfacing the collector rings, replacing the brush holders or springs, changing the brush grade, or a combination of these actions. Similar etching can occur during a long shutdown with the generator at standstill. Carbon brushes should be removed from both commutators and collector rings during long shutdown periods to avoid such etching problems.

The method of eliminating harmful sparking will depend on the cause. In some cases, special brushes may be used. Increased brush pressure may be necessary in other cases. The use of untreated canvas cloth may be useful for removing high-resistance areas on the collector-ring surface.

Collector rings should be resurfaced only when they have been damaged to the extent that good conduction is impossible.

Maintenance workers can use the same methods to resurface collector rings that they use on commutators. Rotary grinders attached to a compound for axially traversing the rings may be used to grind steel collector rings. Whatever the method used for resurfacing collector rings, the runout of the rings must be checked afterward to ensure that acceptable limits for the machine speed are attained. Collector rings must not be ground or cut below the minimum acceptable diameters; at this point, they might fail from centrifugal force. In addition, for collector rings that have spiral grooves in the ring surface to improve brush performance and cooling, many manufacturers strongly recommend not cutting the rings below the bottoms of the spiral grooves. Runouts of 0.001 to 0.002 in. are normally acceptable for 3600-rpm generators. Slightly higher runouts for slower speeds may be acceptable but are not desirable.

1.13 TESTING

Testing is essential to determine a generator's condition. Starting with manufacturing and continuing until the machine is scrapped, tests are required for the following reasons:

- To establish that the generator meets specifications and standards
- To determine that it is suitable for service
- To investigate problems both on- and off-line
- To diagnose failures and determine what repairs are required
- To ensure that repairs made after failures are complete and satisfactory

Section 1.10 describes the many tests and observations needed to keep a generator on-line. Sections 1.12 and 1.14 discuss equipment testing and analysis of tripouts and equipment problems.

This section describes test procedures, equipment, and voltages and discusses test results.

Only those tests that are essential should be performed. Tests take time and personnel, may keep a unit out of service unnecessarily, and, in the case of high-potential tests, shorten the life of the insulation. Utilities must determine whether testing is required, what data are needed, and what tests will provide the required data.

INSULATION RESISTANCE TESTS

Insulation resistance (IR) tests determine the adequacy of electrical insulation with respect to ground or to other conductors. The tests can locate faulty insulation, which can then be repaired or replaced.

ANSI/IEEE Standard 43-1974 (14) describes the recommended methods for testing insulation resistance.

Early test methods applied a direct voltage across the insulation and measured the applied direct voltage and the direct current flowing through the insulation. The quotient of the voltage reading in volts divided by the current in amperes gave an insulation resistance in ohms. This cumbersome method was soon replaced by devices with internal voltage sources that read out directly in ohms and megohms. One commonly used insulation resistance tester is the Megger, built by the James G. Biddle Company. Meggers are now so common that "Megger test" has become synonymous with "insulation resistance test."

Insulation resistance testers come in a variety of forms. The following devices can supply the voltage to the tester:

- A hand-cranked magneto
- A motor-driven magneto (the motor is supplied from a 120-V ac source)
- Electronic circuits supplied from a 120-V ac source
- Electronic circuits supplied from batteries

Insulation resistance testers can be obtained with test voltage levels of 500, 1000, and 2500 V, or a combination of these voltages. Care must be exercised in applying the appropriate test voltage for the rating of the equipment. For example, the 500-V level is used for generator field windings, 250-V circuits, and 600-V equipment. Test levels of 2500 V are normally used for generator stators.

Care must be used in reading the correct scale on those testers equipped with "inner" and "outer" scales. Erroneous conclusions can be drawn that equipment may be grounded when actual IR values of 3 M Ω or less exist.

Generally accepted minimum values of IR have been published in the technical literature. The values are 1 M Ω /kV (of equipment rating) plus 1 M Ω . For example, a generator rated 4 kV would have a minimum IR value of 5 M Ω . IR values lower than the minimum indicate wet, dirty, or deteriorated insulation, which should be repaired.

The insulation resistance of a winding will normally increase with the time of application of the test voltage. This dielectric absorption characteristic can be used to determine the condition of the winding by application of the polarization index (PI). The PI is obtained by applying test voltage continuously for 10 min (the winding should be discharged for 10 min before the test). An IR reading is taken at 1 and 10 min. The PI equals the 10-min reading divided by the 1-min reading.

A dry conventional stator winding in good condition will have a PI of 2.0 or more. Field windings in good condition will have a PI equal to 1.2 or more. Figure 1-26 shows typical curves of insulation resistance versus time and the polarization indexes for four winding conditions.

A PI equal to 1 (or even less) for conventional windings indicates a wet or deteriorated winding, dirt, carbon, or a leakage path. Winding maintenance is normally required, except for water-cooled stator windings, which will normally have PIs of 1 and IR values of about 1 M Ω . PIs of 6 to 8 can also indicate a problem. Such high values have been found on old windings where the asphalt or resin varnishes have cooked out, leaving primarily dry materials, such as mica, glass, cotton, paper, or asbestos. As a result, rewinds have taken place on a planned basis before failures can occur.

A substitute for PI, when 10-min readings cannot be taken, is to divide the 1-min reading by the 30-s reading. A value of 1.5 or greater indicates good insulation condition.

The IR and PI values can be used as guides to determine progress in drying out a winding or to evaluate cleaning effectiveness. Plotting the 1- and 10-min IR values on a curve will show the progress of drying a winding. Figure 1-27 shows a curve of IR values at 1 and 10 min during a winding dryout. Note that the IR values decrease before starting a trend upward, indicating progress. Calculation of the PI during the drying process will also show whether dryout is progressing. Refer to ANSI/IEEE Standard 43-1974 (14), NEMA Standard MG 5.2-1972 (15), and Section 1.12 for methods of dryout.

Values of IR should be corrected to a standard temperature to allow for variations with temperature. The standard temperature normally used is 40°C. Figure 1-25 is a plot of temperature (degrees Celsius) versus the correction factor K_t . The plot shows the inverse relationship of IR to temperature: IR decreases as the temperature of the winding increases. Conversely, the IR will increase as the winding temperature decreases. The

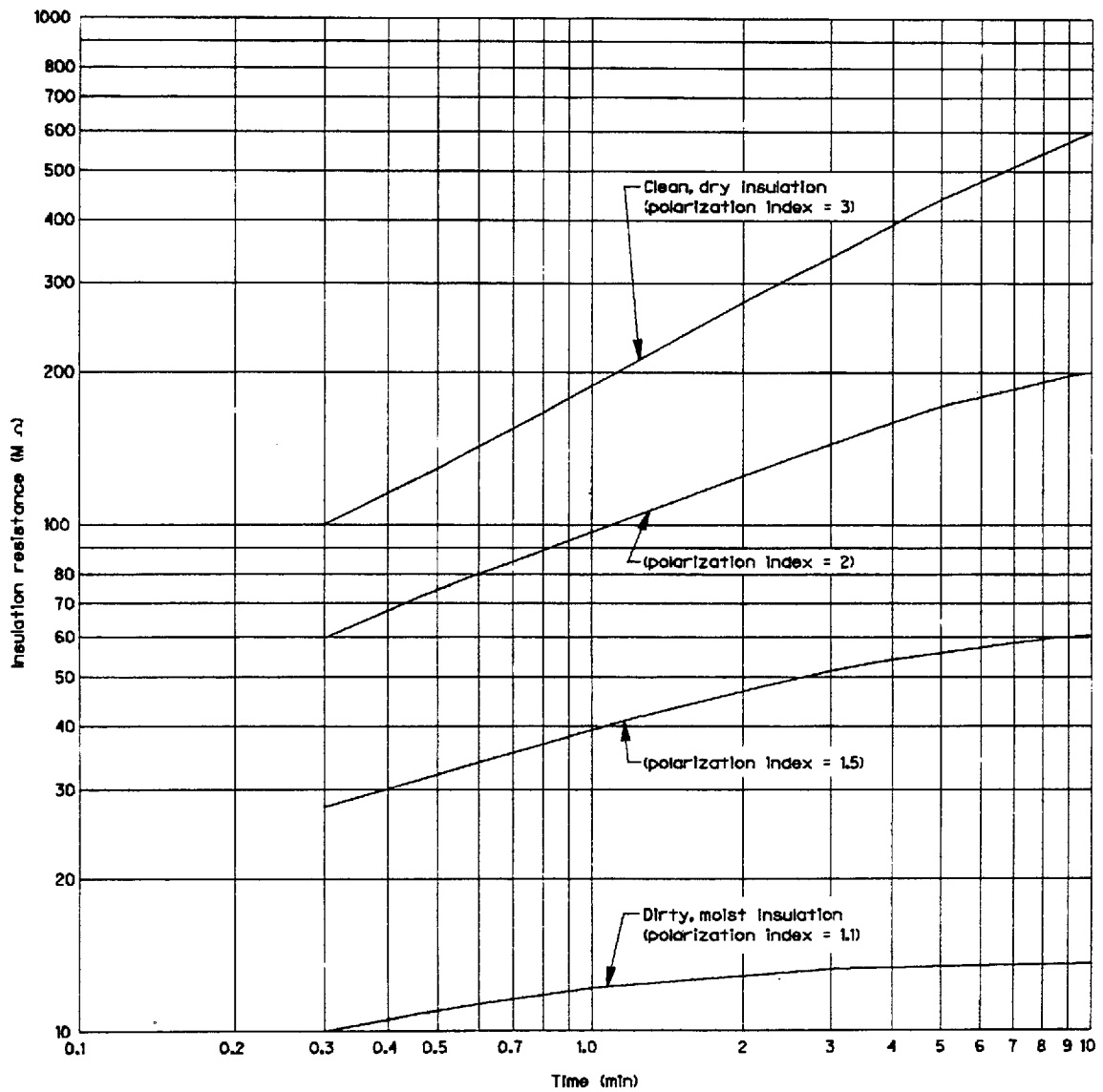


Figure 1-26 Typical Curve Showing Variation of Insulation Resistance With Time

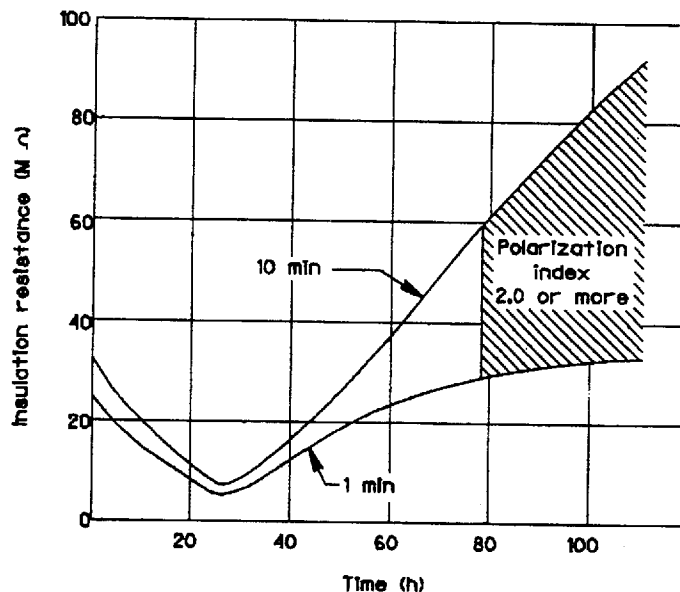


Figure 1-27 Change in Insulation Resistance During Drying

winding temperature must be taken at the time the IR measurements are made in order to correct the IR to a standard temperature.

Corrections of IR values to a standard temperature are particularly critical in detecting long-term trends of insulation condition. Plots of IR values corrected to 40°C versus time (in months or years) can show winding deterioration and permit scheduling of rewinds during planned outages.

Values of IR used for plotting trends should always be taken for the same time of application (for example, the reading at the end of 1 min) and the same winding condition (for example, after cleaning).

IR tests are used both before and after high-potential tests. The earlier IR tests ensure that a winding is suitable for high-potential tests. Both the minimum value of IR and the PI are used to determine suitability for testing. The IR tests following the high-potential tests ensure that winding insulation did not puncture or fail as the test voltage was reduced.

The notes and precautions below point out conditions that will make IR tests safer and more useful.

The windings should be discharged to the frame or ground before an IR test; otherwise erroneous readings may be obtained because of residual charge. After testing, the windings should again be discharged for times equal to or greater than the IR test times.

When used, surge capacitors, potential transformers, grounding transformers, or ground buses must be disconnected to obtain valid IR data. Electrical clearances from associated transformers and circuit breakers must be in effect to protect the tester from shock hazards.

Generators should normally be off turning gear to make IR tests. With cross-compound units tied together at the generator buses, both generators must be off turning gear to obtain valid data; otherwise, the IR value will swing with the rotation of the rotors.

Generators with water-cooled stator windings will have low IR values, normally on the order of 1 MΩ; such values are normal because there are multiple parallel paths to ground through the water hoses. IR values less than 1 MΩ may indicate a winding problem or an abnormally high stator water conductivity.

Generator tripouts via protective relaying have occurred, and subsequent IR tests showed no faulty insulation when tested to ground. The faults in various cases were found in the following ways:

- Visual inspection (burned terminations, burned coil near core edge)
- Tests between phases by opening neutral
- Separation of the generator from a supply cable (cable fault)
- High-potential tests

Low IR values where moisture is suspected can often be proven by reversing the polarity of the tester leads. In other words, the "Earth" or ground lead is connected to the winding and the "Line" lead is connected to ground. If the ratio of IR for normal polarity to IR for reversed polarity equals 5, the winding is wet. This phenomenon is known as the Evershed or electroendosmosis effect and has proven useful in confirming that winding dryout is required. To obtain data, ground the windings for the same periods of time that readings are taken, before and between readings. For example, ground the windings for 5 min; take a 5-min reading with one polarity of the megohmmeter; ground the windings for 5 min; and take a 5-min reading with reversed polarity of the megohmmeter. Data should be taken at the end of each minute to ensure that a full 5-min test is made. Comparisons of IR values for normal and reversed polarities for the same periods of time should be used for calculating the Evershed effect ratio.

Insulation resistance testers have proved helpful in analyzing winding conditions and investigating winding faults. Appendix A contains a useful form for recording insulation resistance data.

HIGH-POTENTIAL TESTS

High-potential (dielectric) tests can be used to check the electrical condition of insulation. Tests on new generator windings prove the windings are suitable for the generator to be placed in service and that no faults or incipient faults exist at the time of the tests. Later in the life of a generator, high-potential tests, made at reduced voltage levels from the initial tests, prove that the windings are suitable for continued service.

Indirectly (conventionally) cooled and direct-hydrogen-cooled windings can be tested with alternating current, direct current, or 0.1 Hz. Direct-water-cooled stator windings may be tested with direct current or alternating current before water is introduced in the windings. Once water has been put in the windings, however, ac testing with normal flow of low-conductivity water is the only practical way to test.

Detailed information on high-potential test methods and test voltage levels can be found in ANSI/IEEE Standards 95-1977 (16), 115-1983 (17), and 433-1974 (18), ANSI/IEEE Standard C50.10-1977 (19), and NEMA Standard MG 1-1978 (20).

Note that there is a risk of insulation failure any time high-potential tests are performed. Prepara-

tions for repairs should be made before such tests are conducted.

Alternating voltage tests at power frequency (ac tests at 60 Hz) provide the base values for most methods of testing. Proponents of ac testing consider these tests the most thorough ones for revealing insulation defects. The voltage stresses produced during these ac tests most nearly duplicate the voltage stresses that occur when the generator is in service, particularly in the end windings. Detractors point out that ac tests are go/no go tests—that is, the windings will either pass or fail the tests. There is no way of observing a trend and stopping the tests before a failure occurs. Detractors also point out that the tests may cause premature failures and that insulation life is reduced by the alternating high-voltage stresses that occur during the 1-min test time.

New stator (armature) windings are tested at twice the rated voltage, plus 1 kV, for 1 min:

$$E_T = 2 E_R + 1 \text{ kV} \quad (\text{Eq. 1-3})$$

Where:

E_T = ac high-potential test voltage

E_R = rated line-to-line voltage (rms or effective value)

The test is performed before shipment or on site if the windings are installed or assembled on site (acceptance proof test). Additional tests after installation may be made at 75 or 85% of the factory test value depending on the type, kilowatt rating, and voltage rating of the generator.

New generator field windings rated up to and including 500 V are tested with an alternating voltage, which has an effective value 10 times the rated excitation voltage but in no case less than 1500 V. The test voltage for field windings rated greater than 500 V is an alternating voltage whose effective value is 4000 V plus twice the rated excitation voltage.

Insulation resistance tests are made before high-potential tests to ensure that windings are suitable for tests and afterward to ensure that the windings did not fail as the test voltage was reduced to zero.

Stator high-potential tests are made by connecting the stator line and neutral connections (if the neutrals are brought out) for each phase. Test voltage is applied to each phase separately while the other two phases of the generator are grounded. Alternating voltage is applied to each phase by

increasing the voltage promptly from zero to the test level, holding the test voltage for 1 min, then steadily reducing the voltage to zero. The test set should never be manually tripped from the test voltage level after the test because of possible ringing (overstressing causing failure of the ground insulation). For delta-connected and wye-connected windings where the neutrals are not brought out, only one test is performed to stress the ground insulation at one time.

Test voltage levels are reduced for maintenance proof tests after the initial tests. Some machine standards refer to maintenance high-potential levels as 0.65 or 0.7 times the factory test level for a new machine. Manufacturers recommend 1.25 to 1.5 times E_R for "suitability for continued service" tests. Certain utilities may use 1.1 to 1.2 times E_R for older, more mature generators. Their reasoning is that it is unnecessary to stress the whole winding at 1.25 to 1.5 times E_R voltage when the coils near the neutral (on grounded wye-connected windings) will never be subjected to such high voltage levels even for a phase-to-ground fault.

Ac tests of water-cooled generators and other very large generators with large winding capacitances to ground may require a shunt reactor in parallel with the winding capacitance in order to permit the use of a high-potential test set with a reasonable kVA rating. Typical test sets are rated 150 to 200 kVA, will test up to 60 kV, and have single-phase supply voltages of 460 or 550 Vac. Series resonant testers are a relatively new development for high-voltage testing with relatively low kVA inputs.

Shown below is a checklist for preparations for high-potential tests. Procedures and precautions are listed to ensure safety of personnel and to avoid damage to the generator from testing. Data sheets for insulation resistance and high-potential tests are included in Appendix A.

The following checklist details the preparations necessary for testing generator stator windings with high-voltage alternating current.

1. Arrange for transportation of all components of the ac high-potential test set from its usual storage location.
2. Locate the test set in a position as close to the stator line and neutral terminals as conditions permit.
3. Arrange for a source to supply power for the test set.
4. Ground all stator-winding resistance temperature detectors (RTDs). Short and ground all machine-current transformers. Small-gage copper tie wire is excellent for this application. Be sure the neutral grounding transformer and all potential transformers have been disconnected. Maintain a list of all grounds to facilitate their removal after the test.
5. Ground the field windings by removing all slip-ring brushes and connect both rings to ground with tie wire or jumpers.
6. Ground the machine's shaft with several turns of copper wire or a ground clamp. The normal shaft-grounding brushes, if present, should be left in position.
7. Remove all machine-neutral bus links, the neutral grounding transformer lead, and either open the phase or line disconnects or remove the appropriate links to isolate stator windings from all other electrical systems. If phase-to-ground clearances are less than 1 ft for 30 kV tests, or 2 ft for tests over 30-kV, rubber blankets should be placed over the ends of all machine leads to prevent arcing to ground during the tests.
8. Depending on the circumstances, a wide range of gases and pressures can be found inside a machine. The following conditions will permit safe overvoltage testing.
 - a. Air at atmospheric pressure only. The machine should be open to help dissipate ozone generated during the test. Air at pressures above 0.5 psig provides too much oxygen for safe testing.
 - b. Hydrogen at purity above 90% and a pressure above 15 psig. Hydrogen at 15 psig has the same dielectric strength as air at atmospheric pressure.
 - c. Carbon dioxide at atmospheric pressure or above.
 - d. Nitrogen at atmospheric pressure or above.
 - e. Mixture of any of the above gases. Purge the mixture and fill with one of the gases to fit conditions a, b, c, or d.
9. The stator water cooling system is to be operated during the test in its normal manner. Conductivity, flow rate, and other parameters

are to be monitored and should not exceed their normal limits in effect at the time of testing. The water is not to be removed. Testing of oil-cooled machines should be in accordance with the instruction manual specifications for high-potential testing.

10. The area surrounding the test set and machine terminals is to be cordoned off with rope and "high voltage" signs located to provide personnel safety. An appropriate number of safety personnel should be available to prevent inadvertent entry into the restricted area by unauthorized personnel. Safety personnel should also be stationed at the machine windings and near the test set. Fire extinguishers should be on hand at the machine windings.
11. Check the insulation resistance to ground for each stator phase with both ends of the other two phases grounded. A 2500-V Megger should be used. On indirectly cooled (conventionally cooled) machines, a 10-min test should be made with test values recorded every 15 s for the first minute and then at additional 1-min intervals to 10 min. The ratio of the 10-min to 1-min readings (polarization index) should be calculated and should be more than 2.0 to permit a high-voltage test.

For water-cooled windings, insulation resistance may be only 1 to 2 M Ω and will not change after the 1-min reading. However, the Megger will show if a dead ground exists.

Data sheets for insulation resistance of rotating machinery and for ac high-potential test of generators and synchronous condensers are included in Appendix A.

All tests will last 1 min for each phase, with all other windings grounded unless otherwise noted. Megger readings should be taken on all three phases immediately before the high-potential tests to determine whether the windings are suitable for testing and immediately afterward to establish that the windings were not punctured during the high-potential tests. The winding under test should be discharged to ground when the test is completed. High-potential tests should not be performed on humid days.

Direct voltage or dc high-potential tests and test procedures are described in ANSI/IEEE Standard 95-1977 (16). A thorough study of this standard is required to ensure that the time rate of voltage

application, recording of voltages and currents, and plotting of data are technically correct so that appropriate evaluation of the winding condition can be made. Skilled engineers or technicians are normally required for dc testing. (Note that changes of test-set supply voltages and starting fans around a generator may affect the test data).

Test values for dc tests are 1.7 times the ac 60-Hz test values. For example, a new 13.8-kV stator would be tested at 23.6-kV ac or 40.1-kV dc.

Proponents of dc testing prefer this type of test because impending failures can be predicted and the tests halted before failures damage the insulation. Dc test equipment is also much smaller and can be transported in an automobile. In contrast, ac test sets consisting of a transformer, regulator, sphere gap, resistors, and other parts may weigh from 4000 to 8000 lb and must be transported by truck.

Precautions and preparations noted in ANSI/IEEE Standard 95-1977 (16) and similar precautions that apply to ac testing should be observed for dc testing.

Very low frequency (VLF) (0.1-Hz) high-potential test equipment and procedures are a fairly recent development and are described in ANSI/IEEE Standard 433-1974 (18). The intent of developing the VLF test was to stress the machine insulation in the same way that power frequencies do and to reduce the size of test equipment required. While VLF test equipment is significantly smaller than ac 60-Hz testers, the VLF testers are not as readily transported as dc testers. One manufacturer and certain utilities regularly use VLF testing.

Test values (rms) for VLF (0.1-Hz) testing are 1.15 times the ac 60-Hz (rms) test values that would be used. The equivalent crest value for 0.1-Hz tests therefore is $1.15\sqrt{2} = 1.63$. (The rms value is the effective value.)

OTHER ELECTRICAL TESTS

Power factor tests are used by some utilities to test ground insulation on individual stator phase windings. The test is usually conducted up to and including 100% line-to-ground voltage, but may be tested at reduced voltage levels depending on the test equipment. The power factor is the ratio of the stator insulation loss to the volt-amperes at a specified test voltage. This can be represented as follows:

$$PF = \frac{W}{VI} \quad (\text{Eq. 1-4})$$

Where:

W = watts loss

V = test voltage in kilovolts

I = charging current in milliamperes

A power factor test set is used to perform the test. Evaluation of the test data is done by comparing the new data with previous results, other phases in the same machine, or other generators of similar manufacture and rating. In general, machines up to 24 kV have a power factor of 3% or less, depending on the insulation system.

A power factor tip-up test may also be performed for further evaluation of the insulation. The tip-up test is defined as the increase of power factor as voltage is increased from 2 kV to 10 kV or to operating voltage. ANSI/IEEE Standard 286-1975 (21) provides more information about power factor tip-up testing.

Most utilities, and certain manufacturers, believe that high-potential testing is more useful for finding faults and a better indicator of winding condition. Certain utilities rely on power factor testing and tip-up testing for determining the condition of ground insulation and even for predicting when generators should be rewound. Power factor tests are not normally used on water-cooled stator windings because of the low insulation resistance to ground, usually on the order of 1 to 3 M Ω .

The dissipation factor $\tan \delta$ test, also called loss-tangent test, is a test for measuring the dielectric loss of insulation at predetermined values of temperature, frequency, and voltage, or dielectric stress, in which the dielectric loss is expressed in terms of the tangent of the complement of the insulation power factor angle.

Measurements of this characteristic are made with a Schering bridge.

Coil manufacturers may use dissipation factor $\tan \delta$ tests or power factor tests for quality control, to indicate whether a void-free insulation is being produced.

Dissipation factor $\tan \delta$ values may also be used for tip-up tests in evaluating insulation quality.

Partial-discharge tests measure small charge variations (in coulombs) by testing the corresponding current variations. A discharge detector (ionization or corona detector) is an instrument that can be connected in or across an energized insulation circuit to detect current or voltage pulses produced by electric discharges. Section 1.10 and the paragraphs on RF or EMI monitors discuss this subject in greater detail.

Slot-discharge tests are performed to evaluate the coil surface grounding in the slot portion. Slot discharge is the sparking between the outer surface of coil insulation and the grounded slot surface, caused by capacitive current flow between conductors and iron. The resulting current pulses have a fundamental frequency of a few kilohertz. The slot-discharge test consists of applying approximately 7 kVac between the winding and ground and observing the waveform on an oscilloscope. This waveform is compared to a waveform of one coil side arcing to the slot at a single point. Line disturbances are usually filtered out to obtain accurate slot-discharge phenomena.

Slot discharge can also be detected with an electrostatic probe, particularly in the end windings. An electromagnetic probe can also be used to span each coil in the slot area to search for partial discharge.

Surge comparison tests are used primarily to test the turn-to-turn insulation in multiturn coils such as those used in hydrogenerators and generator/motors. The tests are used for quality control during coil manufacture and may be used on coils installed and wedged in the slots.

The surge comparison tester is an electronic device that stresses turn and ground insulation by application of a repetitive, short-duration surge voltage alternately to two test coils. The ringing of one coil is compared to the ringing of the other coil by observing the traces on an oscilloscope. If a single trace (overlapping traces) is observed, the turn insulation is good. If a double trace is found, the turn insulation is faulty. The double trace is caused by the difference in impedance between the good coil and the coil with faulty turn insulation.

Complete windings can be given surge comparison tests, but the voltage surge dissipates rapidly from the point of application toward the other end of the winding. Therefore, such tests may not be sensitive enough to detect turn faults away from the point of surge voltage application. It may be necessary to open parallel circuits in the windings to increase the sensitivity of the tests. Surge comparison tests may show reversed coil groups or phases, incorrect numbers of turns in a coil, and faulty coil-to-coil or coil-to-ground insulation.

Test voltage levels must be greater than 350 V (peak), which is the minimum sparking voltage for a uniform field in air (Paschen's law). Test levels must not be too high because of the risk of failing the ground insulation. IEEE Standard 522-1977 (22) provides the following formula:

$$V_p = k_1 E_R$$

(Eq. 1-5)

Where:

V_p = momentary peak test voltage across the coil
(not to exceed peak value of voltage applied as ground test nor to be less than 350 times the number of turns in the coil)

k_1 = empirical factor (1.0 suggested for trial use)

E_R = rated rms line-to-line voltage

IEEE Standard 522-1977 gives precautions regarding the use of this formula. For low-voltage machines, the test levels from this formula may be too low and may not adequately stress the turn insulation. For a high-voltage, low-kilowatt machine, the test level may be too high.

Turn insulation tests using testing techniques other than surge comparison tests are described in IEEE Standard 522-1977 (22).

Field (or rotor-winding) impedance tests can be made using the test setup shown in Figure 1-28. Tests are made using an ungrounded ac source, an accurate ac voltmeter, and an ac ammeter. Data should be taken at several voltage levels (for example, 30, 60, 90, and 120 V), the associated currents recorded, and the impedances calculated. Note that the impedances change with voltage. Record whether the rotor is in or out of the stator. Data from these tests can be compared to earlier data from the same rotor or from a similar rotor

to indicate whether shorted turns or shorted coils exist. A similar test setup can be used to perform a pole-drop test, provided that the conductors for each pole are accessible. In this test, the voltage across each pole is compared with the voltage across every other pole. Significant variations in values indicate shorted turns or coils.

A flux-probe test is a method of determining whether turbine generator rotors have shorted turns and which coil has shorted turns. A flux probe (search coil) is inserted radially through the core and into the air gap, and the output of this stationary coil is connected to an oscilloscope. A pickup coil is used near the shaft outside the stator to identify the shaft position relative to the field windings (that is, which pole is the 0° pole and which is the 180° pole in a 2-pole machine). The generator is isolated from the system, and the stator windings are short-circuited (all three phases). This task can be accomplished by installing jumpers on the high-voltage side of the unit transformer. The unit is brought up to speed, and field current is carefully applied to give enough stator current (25 to 40%) so that the fundamental flux of the field is essentially cancelled by the armature reaction. The remaining variation in flux density, as seen by the search coil, is predominantly the slot leakage flux. Pictures are taken of the search coil output of voltage waves from each field-winding slot. Careful analysis of the voltage

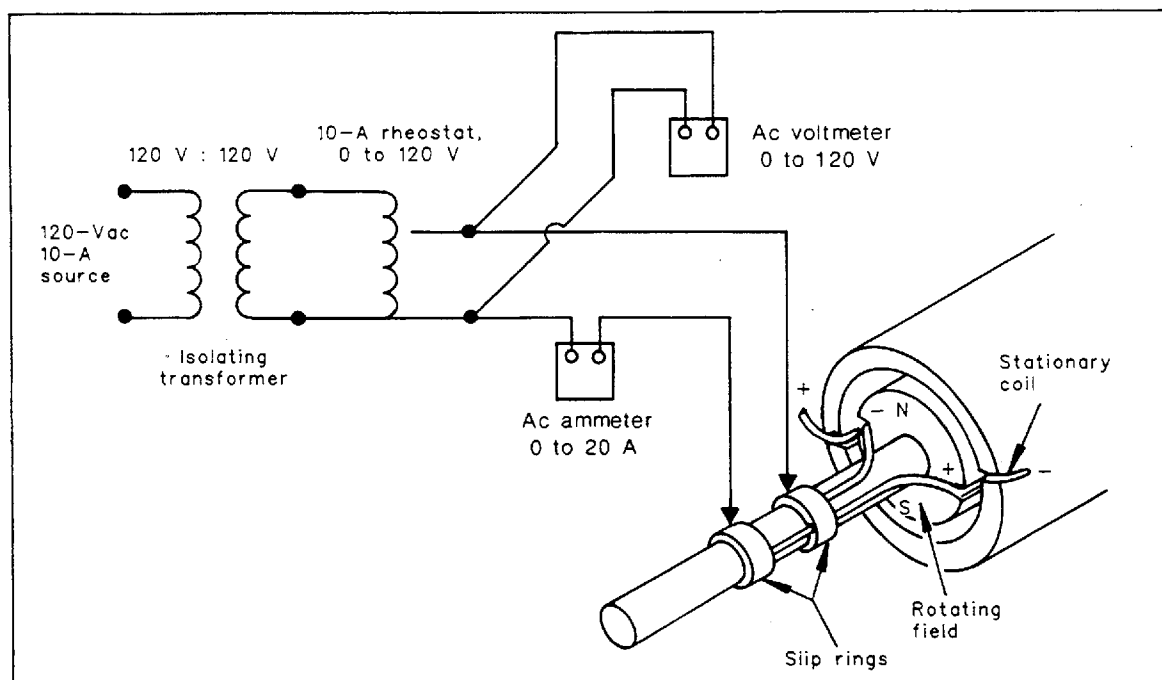


Figure 1-28 Test Setup for Measuring Generator Field Impedance

waves, and comparisons of poles, will indicate whether shorted turns exist, how many turns are shorted, and which coil has the shorted turns.

Flux-probe tests can be made under open-circuit conditions, but the short-circuit tests have proven to be much more sensitive (21).

GENERATOR CHARACTERISTICS TESTS

Tests for obtaining generator characteristics and machine parameters may be performed in the factory, on site during startup, or after startup. ANSI/IEEE Standard 115-1983 (17) provides details of the appropriate tests for obtaining data. IEEE Standard 115A-1984 (23) is a supplement to ANSI/IEEE Standard 115-1983 and provides information for obtaining machine parameters by standstill frequency-response testing.

Values of machine parameters may be obtained from calculations or from machine prototype testing. Tests may be performed on the specific generator being applied. Section 1.9 lists the parameters used for stability studies and for other data needed to integrate a generator into a system and operate it successfully.

FACTORY TESTS

Tests in the factory are still performed by some manufacturers, at least on prototype turbine generators. The costs of such tests are substantial because of the assembly, wiring, protection, shop space, and test technicians involved. One major manufacturer has elected to discontinue factory tests because of their costs. A comprehensive test program may take weeks to set up, test, and then dismantle. Such test programs can include open-circuit, short-circuit, sudden short-circuit, heat runs, and many other tests described in ANSI/IEEE Standard 115-1983 (17) and IEEE 115A-1984 (23).

ON-SITE TESTS

After installation, tests can be performed on site for those machines not assembled and tested in the factory. Hydrogenerators and generator/motors are normally tested after assembly on site because of the massive sizes and weights involved. Tests include dielectric (high-potential) tests, generator parameters, and performance characteristics. ANSI/IEEE Standard 115-1983 (17) and IEEE Standard 115A-1984 (23) provide comprehensive information for testing on site.

1.14 TROUBLESHOOTING

Perhaps the most challenging and stimulating facet of the power industry is the investigation or troubleshooting of generator problems, faults, operations, erroneous operations, electrical and physical conditions, and deviations from expected parameters or responses. It is first a mental exercise to visualize the equipment involved and all the external and internal influences on the equipment. Next the troubleshooter must obtain inputs from whatever devices (such as meters, relays, core monitors, oscillographs, trip-sequence monitors, charts) are available and also inputs from persons associated with the event. There is then an analysis of all data available; the troubleshooter draws conclusions and decides upon the required solution. A postmortem examination may help prevent recurrence of that event or a similar one.

INVESTIGATING GENERATOR ELECTRICAL TRIPS

To analyze an electrical tripout, a person needs knowledge of the protective circuits that are used, the relay targets found after tripout, oscillograph records of critical voltages and currents, and observations from those persons on site at the time of the tripout. Electrical, physical, or chemical tests may be required to develop conclusions about the cause of a tripout.

Stator faults that normally cause a tripout are winding insulation breakdown from phase to ground or phase to phase. Ground relays are applied for phase-to-ground faults. Differential or overcurrent relays are applied for phase-to-phase faults or multiple-ground faults where two or more phases fail to ground.

Other generator conditions may actuate lock-out relays similar to those actuated by electrical faults. Such conditions are negative-sequence (I_2) currents, loss of stator coolant, overcurrent, excessive volts per hertz, vibration, motoring, and loss of synchronism.

Rotor faults such as a field-winding ground may cause an electrical trip on some systems, but certain operating companies will actuate an alarm instead and bring the generator out of service by a controlled shutdown. Proponents of alarms alone argue that one ground will not normally cause damage. (If a second ground develops, however, major damage, including destruction of the rotor forging, could occur.) Proponents of tripping for rotor grounds emphasize that a single rotor

ground may be caused by a cracked conductor and that severe burning of the rotor forging and/or retaining rings could occur if the generator continues to operate. Also, one rotor ground can cause bearings to vibrate, which may damage the bearings if the generator continues to operate.

Rotor-related trips can be caused by loss of excitation on some units. The loss of excitation could be caused by external excitation circuits, carbon brushes, openings in the field winding, or a field-breaker trip.

Rotor problems can be analyzed by the use of relay targets, field temperature charts, stator voltage and currents, and stator kilowatts and kilovolt-amperes-reactive. Vibration charts, oscillographs, and trip-sequence monitors may be useful for the investigation.

The location of rotor-winding grounds is often difficult and time-consuming because of the large number of conductors, circuits, components, and devices involved with the rotor winding. If the generator relays trip the unit for a rotor-winding ground, all tests are normally made at standstill, although testing at some speed off-line may be required for speed-related grounds.

If the unit is relayed for alarms only for a rotor-winding ground, there are tests that can be made on-line to locate the ground before the unit is removed from service. An outline of steps to locate grounds is shown below. This procedure does not apply to a brushless excitation system. All insulation resistance tests should be made with a 500-V tester.

In some cases, the grounds are in the field windings and, in other instances, the "field ground" has been a ground external to the field. Examples of the latter are grounds that have developed in collector brush rigging, in dc cables to meters or collector rings, in main or reserve exciters, and in field breakers. In addition, certain suspected field grounds were not grounds at all, but a problem with the field-ground detector relay or associated circuitry. A sequence of checks is shown below, which may help determine the cause of a field ground while in service or after being removed from service.

1. Dc generator excitation systems

- a. After an alarm occurs, try several times to reset the field-ground detector. The ground may be an intermittent fault, may be caused by stray material in the collectors or breakers, or may be an inadvertent ground from someone working near the brushes.
- b. If the ground stays on, transfer to the manual (rheostat) regulator from the automatic voltage regulator to see if the alarm clears. If the alarm clears, check the automatic voltage regulator and associated circuits (such as the amplidyne).

If the ground remains, change the excitation supply over to the reserve exciter. Again try to reset the field-ground detector relay. If the ground remains, make a visual check of the collector rings and brush rigging for the cause of the ground.

If the ground clears after changing to the reserve exciter, check the main exciter, main field breaker, and associated cables and wiring for the cause of the ground.
- c. If the ground remains after changing exciters, check the positive and negative voltages to ground with both the control room voltmeter—Test (+) and Test (—)—and a portable high-resistance meter (a digital meter or similar instrument). Allow time for the meter readings to settle out. The normal voltage on each polarity to ground should be zero but can be up to 10 V if the insulation resistance value of the field, brush rigging, cables, exciters, or field breakers is low.

High voltages that decay slowly with the use of low-impedance voltmeters may indicate inadequate shaft grounding and the buildup of steam-flow electrostatic voltage in the field-winding capacitance.

Compare the positive- and negative-to-ground voltages with the total voltage applied to the field. If either the positive- or negative-to-ground voltage is equal to the total field voltage while the opposite polarity is near zero, expect the ground to be near a collector ring or external to the field winding. For example, one "test positive" equaled 257 V and "test negative" showed zero, while the field voltage was 257 V. The ground was found at the field breaker and was caused by tracking from a contact to ground.

Voltage readings to ground greater than 10 V on both rings indicate low insulation resistance or a ground in the field windings.

- d. While still in service, grounds external to the field should be checked by clearing or disconnecting excitation instrument wiring to see if the ground clears. For example, pull fuses that supply voltage to the voltmeter and field temperature recorder. If this step fails to clear the ground, disconnect the shunts for field ammeters and field temperature recorder, if the shunts are accessible.
- e. If step d fails to clear the ground, the unit should be removed from service promptly via a controlled shutdown. With all sources of excitation removed, the field can be Megger tested during coastdown to determine if the ground is speed related.
- f. With the generator at standstill, remove all the collector-ring brushes and Megger test the field at the collector rings and then at the brush rigging, which includes all externally connected excitation equipment. Use a 500-V Megger. Determine whether the field winding or the circuits external to the field are grounded.
- g. If the ground is in the field, perform a split-voltage dc test. Use a motor-driven or gasoline-engine-driven dc welder with the dc leads isolated from ground. Apply about 30 V across the two polarities of rings with all brushes removed, and read the voltage from each ring to ground. The split of voltage readings will indicate how far through the field windings the ground is for a single point ground, if the ground resistance is not too high. The sum of readings should equal the total. If the ground is near a collector ring or the radial studs, one ring reading will be nearly zero while the other ring will read nearly the total applied voltage. Be certain the field-ground detector is out of service and the panel Test (+) and Test (-) switch is in the "generator volts" position for the split-voltage test. The Test (+) or Test (-) position switch grounds the field through the meter.
- h. If the field ground is near a collector ring, carefully clean the ring (by vacuuming or blowing with dry air), and check the collector-ring insulation and around the radial studs. If the ground remains, clean the ring insulation with cloths slightly dampened with solvent. Do not use excessive amounts of solvent for cleaning because the liquid may carry carbon and other contaminants into cracks and openings where they would be impossible to remove. Use vacuum, dry air, or slightly dampened cloths. Should this cleaning not clear the ground, check the radial studs, then open the collector end of the generator for further checks. It may be possible to clear the ground without removing the field from the generator. If not, the field will have to be removed to clear the ground, and later reinstalled (or a spare installed, if available).
- i. If the field ground is not near a collector ring, open the generator and check the field windings. If the ground cannot be cleared, the field must be removed for repair.
- j. For a ground on the brush rigging or external excitation system, check the brush rigging, cables, field breakers, and excitation wiring until the ground fault is found and cleared.
- k. If the ground clears when the field is at standstill, the ground may be caused by centrifugal forces related to speed. As noted in step d above, the field should be Megger tested during coastdown (with no field voltage) when the unit is removed from service. If the ground is speed related, the field must be Megger tested (and split-voltage dc tests must be made to locate the fault) while spinning at various speeds, up to rated speed, with all collector brushes removed. If these tests confirm a speed-related field ground, it may be necessary to high-potential test the field at

standstill or remove and dismantle the field to find the fault.

2. Alterrex excitation systems

Note: The Alterrex field and generator field have separate ground detection circuitry. The discussion below pertains to main generator fields.

- a. After an alarm occurs, try several times to reset the ground detector relay. Hold the reset several seconds to allow capacitors that may be used for shaft-voltage suppression or other purposes to charge or discharge.
- b. If the ground remains, check the voltage from each collector ring to ground with the panel meter—Test (+) and Test (—)—and a high-resistance voltmeter at the collector rings. Check the total voltage between rings. The checks with the high-resistance voltmeter must be made with the field-ground detector out of service and the panel Test (+) and Test (—) switch in the “generator volts” position. Readings showing near zero on one ring and near total voltage on the other ring indicate the ground is external to the field. Other splits of voltage indicate the ground is in the field. Voltage polarity reversals may indicate that the ground is external to the field.
- c. If the ground is external to the field, check the wiring to the field voltmeter and field temperature recorder. Check wiring to the shunts for the field ammeter, the field temperature recorder, and similar wiring.
- d. If the ground remains and is external to the field, reduce field current to the minimum required for the load and open the 5-pole switches to each diode bank, one at a time, to see if the field ground clears.
- e. If the ground cannot be cleared or is in the field, remove the unit from service on a controlled shutdown and Megger test the field as the machine rolls down. At standstill, remove all brushes from the collector rings. Megger test the field and the brush rigging with a 500-V Megger. Determine whether the ground is in the field or in the brush rigging and associated

circuits. Follow steps g through k under “Dc generator excitation systems.”

LOCATING LEAKS IN WATER-COOLED STATOR WINDINGS

Indicators of stator water system leaks inside the generator are described in Section 1.10. If the hydrogen pressure inside is greater than the stator water pressure, the stator water conductivity will increase substantially. When the generator is degassed under these conditions, the stator water pumps should be shut down to keep from filling the generator with water when the casing pressure is less than the stator water pressure. In addition, the stator water deionizer(s) should be isolated to prevent poisoning the resins during the CO₂ phase of gassing or degassing.

Other indicators of a stator water system leak are an increased volume of hydrogen in the vents from the stator water tank and abnormal variations among stator water outlet temperatures as shown by thermocouples in stator bar outlets. Generator manufacturers advise that variations from the average temperature, and variations among the highest and lowest temperatures, are normally only a few degrees. Variations greater than a few degrees indicate that a serious problem may exist.

Leaks are sometimes caused by a loose piece of material vibrating into the insulation and hollow strands of the stator bars. This causes a high rate of hydrogen use. Abnormally high rates of hydrogen use should be investigated immediately; a winding failure could occur at any time, depending on the location of the leak.

Stator-system leaks inside the generator can be found by opening the generator, putting the pumps back on briefly, and looking for water. Leaks under thick layers of insulation may take time to show up. Another technique is to pressurize the stator water system with air to look for air or water leaks or to listen for air leaks. Sonic detection devices may be used. Note that the air-pressure test can be made before removing end bells or end brackets to determine which part of the generator needs to be opened to accomplish a repair. Handholes can usually be opened at each end of the generator to determine where the leak is. Be certain to check carefully for the location of the highest noise level; sound will carry throughout the casing, and one can be misled into opening the wrong part of the machine.

Freon should never be put in the stator water system to trace leaks (with a Freon detector). The Freon may hydrolyze under certain conditions to form hydrofluoric and/or hydrochloric acid. These acids can damage iron-based materials and initiate cracks in stainless steel piping.

Look and listen for leaks in the stator bars, water connections, Teflon hoses, headers, piping to the headers, and other components, such as bushings or neutral connections, that may also be water-cooled.

Leaks have been found in water boxes to the bars, ferrules and piping connections on the Teflon hoses, piping to the ring headers, and internal piping, such as for antisiphon lines.

CARING FOR COLLECTOR-RING AND EXCITER BRUSHES

Extensive information is provided in Section 1.12 about the operation, maintenance, and repair of collector rings, dc exciters, and brushes. Reasons for poor brush performance are frequently elusive; a logical, step-by-step approach must be taken to resolve problems. Several changes made simultaneously may offset one another, and poor performance will continue. Further, if the performance improves from several changes, the engineer will not know which change was effective.

Carbon-brush books, manufacturers' instructions, and IEEE literature provide substantial information on the operation of carbon brushes. Several other points to consider are listed below:

- If brush performance has never been satisfactory, check the original design and installation.
- If there is a change from satisfactory to unsatisfactory brush performance, check for the following:
 - Incorrect reassembly following maintenance work
 - A change in loading of the machine
 - A change in ambient conditions: temperature, contaminants, oil, gases, humidity, and coolant
 - A change of brush grade or a change in the characteristics of brushes that did perform well before
 - Inadequate routine maintenance: insufficient brush pressure, brushes bound up in brush boxes, carbon dust and dirt, poor

shunt connections, selective action (unequal sharing of current)

- Too many or too few brushes
- Poor surface conditions on the collector rings or dc exciter commutators
- Deteriorated insulation and low insulation resistance to ground

Carbon brushes require major attention each day the generator is in service. A walk-by inspection should be made each shift to ensure that the brushes are performing satisfactorily. A close inspection of each brush should be made at least weekly and more frequently if there have been brush problems. During this weekly close inspection, checks should be made for overheated shunts, short brushes, brushes binding in the holders, selective action, carbon dust, dirt, oil, sparking, vibration, chattering, overheating, poor collector rings, and poor commutator surfaces.

Carbon brushes have worn out overnight because of extremely low humidity during subzero temperatures. The collector-ring or commutator film, which acts as a lubricant, is stripped away because of low moisture. Brush friction increases dramatically, and the brushes grind away. During these extremely low humidity conditions, it may be necessary to introduce water into the cooling air to obtain satisfactory brush performance or to use brushes especially developed for low-humidity applications (high-altitude brush grades for aircraft generators).

Brushes are often removed to increase brush-current density or to maintain the brushes while the unit is in service. The removal of too many brushes can lead to severe arcing and brush-box and rigging flashover. An erroneous operation by a major utility involved collector-ring brush magazines that were removed by maintenance personnel. Too many magazines were removed, and the brushes remaining in service became severely overloaded, disintegrated, and caused a flashover.

Another erroneous operation developed from a gummy buildup inside the brush boxes, causing the brushes to "hang up." When brush wear progressed to the point that the remaining brushes in contact with the collector ring became overloaded, a flashover occurred. The gummy deposits were later removed by sandpaper. A similar effect will result from oversized brushes that do not feed through the brush boxes. Each new shipment of carbon brushes should be checked

with a suitably sized brush box to ensure that each brush will feed through.

As long as carbon brushes continue to be used, operators and maintenance personnel will need to pay close attention to this equipment to avoid failures.

CHECKING FOR STATOR HYDROGEN LEAKS

Searching for hydrogen leaks is a time-consuming and often frustrating job because the leaks are usually small and the generator and hydrogen piping cover such a large area. Various methods and instruments have been used for leak detection. Soapsuds or trade products like Leak-Tec and Snoop may be old-fashioned and crude but often prove to be effective. These liquids must not be used around the insulation on the hydrogen-seal bracket because they will reduce the insulation resistance. Instruments such as explosive-atmosphere devices are also useful. Sonic detectors have not been very successful because of ambient steam and air noise around the generators. Freon in hydrogen must not be used because the Freon detector has a hot element, which could cause a hydrogen explosion. Odorants in the hydrogen have been suggested in instruction books, but the author is not aware of any case where this method has been used.

Patience, persistence, and the use of both liquids and instruments is usually required to locate many elusive leaks. Quite often it is necessary to go back over parts of the hydrogen system that were previously checked in order to pinpoint the leaks.

The examples of hydrogen leaks below show the wide variety of places where they can occur:

- Bad seal at terminal stud, which produces leak at collector rings
- Bad weld in generator casing
- Paste-seal joint in bushing well
- Broken instrument diaphragm in control cabinet
- End-bell circumferential joints
- Hydrogen shaft seals
- Stator water system
- Cooler-tube leaks
- Around bushings (inside the generator); triple-boiled linseed oil or silicone oil dried out or lost from the recess between the bushing flange and bushing well

Table 1-5 is a checklist to help locate hydrogen leaks.

CHECKING ROTOR-SHAFT VOLTAGES

The sources of shaft voltages are described in Section 1.3 in the paragraphs on bearing insulation. They include the following causes:

- Magnetic dissymmetry
- Electrostatic charges from the flow of dry steam
- Ripple voltages from solid-state excitation systems conducted to the shaft via the field winding capacitance
- Voltages caused by magnetized turbine generator components

Shaft voltages on turbine generators should be measured using an oscilloscope, with the machine loaded and on-line. Measurements with voltmeters and volt-ohm-milliammeters (VOMs) can lead to erroneous conclusions about the adequacy of shaft-grounding devices. The steps below are suggested:

1. Dc-couple the oscilloscope (observe alternating current and direct voltages)
2. With shaft-grounding devices in contact, measure the peak-to-ground voltage on the generator drive-end shaft. Contact the shaft with a No. 10 AWG copper wire.
 - a. The voltage should be 6 V or less (peak-to-ground).
 - b. Little or no direct voltage should be present.
 - c. If the voltage is greater than 6 V (peak-to-ground), the grounding devices are not providing good contact; clean or replace them as necessary. Voltages of 6 V or more can result in bearing or gear damage from shaft current.
3. With shaft-grounding devices in contact, measure the generator collector-end (non-drive-end) shaft voltage. Determine the normal value (10 to 20 V are expected for large generators). If the collector-end shaft voltage starts to trend to a lower value, the problem is lower insulation resistance at the collector end of the generator. Locate and clean or replace bad insulation as required.
4. Always record unit load (in kW), field current and reactive (in kVAR) with the shaft-voltage data. Shaft-voltage values on the collector-end generator shaft will vary with these parameters.

Table 1.5 Generator Hydrogen System: Checklist for Leaks

1. Generator shell (exciter shell)
 - a. End bells (end shields, bearing brackets)
 1. Circumferential joints
 2. Horizontal joints
 3. Handhole plates
 4. Bolts
 - b. Coolers
 1. Flanges to shell
 2. Tubes (Check vents for hydrogen.)
 - c. Glands
 1. RTD wiring
 2. Thermocouple wiring
 - d. Bushings
 1. Bushing flanges and joints
 2. Mounting plate
 3. Bushing-well cover
 4. Bushing-well gasket (Seal joint or weld to generator.)
 - e. Stator water system
 1. Conductivity increase
 2. Hydrogen at vent from storage tank (Check purity and volume of flow.)
 - f. Hydrogen shaft seals and seal-oil system
 1. Bearing-oil drains
 2. Bearing cavities
 3. Stuck float valve in seal-oil trap
 4. High-level alarm for hydrogen-detaining tank (and tank vent)
 5. Valves and welds
 - g. Access plates and handhole covers in shell
2. External piping
 - a. Water and oil leakage detectors
 1. Piping
 2. Welds to generator casing
 3. Float switch (switches)
 4. Valves
 5. Line welds
 - b. Gassing and degassing piping and valves
 1. Hydrogen piping and valves
 2. CO₂ piping and valves
 3. Purging lines and valves
 4. Vents
 - c. Control cabinet
 1. Pressure gage, lines and valves
 2. Fan differential gage, lines and valves
 3. Purity meter, lines and valves
 4. Test connections
 5. Vent
3. Other
 - a. Collector rings
 - b. Gas meter and valves
 - c. Miscellaneous hydrogen piping
 - d. Gages
 - e. Core monitor and associated piping
 - f. Miscellaneous vents (Check purity and volume of flow.)

5. If a current probe is available, lift the shaft-grounding device at the generator drive end, ground the shaft with No. 10 copper wire, and measure the current through the wire to ground. If little or no current is measured, the collector-end insulation is good and no current loops exist. Caution: Never measure the current from shaft to ground at the collector end of the generator; the No. 10 wire shorts the generator shaft voltage to ground, produces very large currents, and may set off a hydrogen or oil vapor explosion if either is present. The turbine end of the generator is normally grounded with copper braids or carbon brushes.

GROUNDING ROTOR SHAFTS

The need and methods for grounding turbine generator rotor shafts are described in Section 1.3 in the paragraphs on bearing insulation. Troubleshooting the adequacy of rotor-shaft grounds is described in the preceding paragraphs. Note that inadequate or poorly maintained grounding devices can cause failures of bearings, gear drives, and other close-clearance devices.

One indication that a rotor shaft is not adequately grounded is a high-voltage indication when field winding Test (+) or Test (–) to ground tests are made. The voltages may swing up to 100 or 200 V (due to electrostatic voltages from dry steam flow), then slowly decay to near zero. The rate of decay is determined by the internal resistance of the Test (+) and Test (–) voltmeter. If such high readings are found, immediate steps should be taken to adequately ground the shaft at the drive end of the generator.

1.15 STORAGE

Manufacturers of generators normally provide comprehensive instructions for the storage of major and minor components both before startup and for those components and spare parts stored indefinitely. These instructions include lists of materials for preservation, recommendations for receiving, inspection, storage facilities, storage environments, surveillance, and maintenance during storage.

The following are primary storage considerations:

- Protection from the elements
- Condensation prevention

- Protection from dust and dirt
- Safeguarding from mechanical damage

Electrical insulation must be protected from the deterioration effects of moisture, temperature, and contaminants.

Preservation materials include greases, oils, primers, paints, sprays, slushing compounds, rust preventatives, coatings, desiccants, waxed papers, bags, tapes, and hardboard. Specific materials and their suppliers are designated for each component.

Receiving instructions pertain to inspections for shipping damage to parts, skids, boxes, and protective coverings, noting any water (salt or salt-water intrusion), and taking inventory of parts received.

Storage facilities and environments point out requirements for indoor or outdoor storage, supports, wrappings, temperatures, heat or humidity control, and exclusion of rodents, insects, and reptiles. Equipment that requires "exercising" during storage should be located such that the required functions can be performed readily.

Surveillance and maintenance instructions provide frequencies for checking each component, a list of what should be done and what tests should be made, and instructions for the maintenance required to keep the equipment in good condition.

Manufacturers may provide specific instructions for different phases of storage, such as

- Long-term storage
- Protection during installation
- Protection of assembled equipment after installation and prior to startup

Instructions for short and long outages after the machine is brought on-line may also be provided by manufacturers. If the information is not available, operators of the generators should develop directions of their own for preservation of generators. This volume contains numerous suggestions for accomplishing this task.

The storage procedures noted above also apply to the storage of associated equipment and auxiliary systems for the generator. For example, excitation systems, hydrogen seal-oil systems, stator water systems, and spare parts should be protected. Special instructions are required, such as leaving brushes out of dc exciters and out of collector rings until the machine is brought into service, or draining water-cooled diodes, or keeping heat exchangers dry to avoid freezing. Auxiliary system equipment and spare parts for auxiliary systems, such as motors and pumps, should be exercised

and lubricated to ensure that the equipment will be operable when placed in service.

A guide for storage of spare generator stators, rotors, and stator bars is included in Appendix B.

1.16 SPARE PARTS

Rotating electrical machines have proven very reliable historically, but eventually most generators will require maintenance or repairs. Operating duty, faults, improper operations, abuse, and inspections will indicate when and what work needs to be done. To return a generator to acceptable running condition, spare parts, materials, and skilled craftsmen will be required. Most manufacturers or competent repair shops can provide materials such as resins, wedges, and other winding supplies on short notice, as well as furnishing skilled workers. Spare parts such as coils, core iron, and bearings may not be so readily available. Generator operators must then determine from experience which parts to stock and which parts a manufacturer can supply in a reasonable time.

WINDINGS

The spare coils or bars required to repair stator windings are frequently long-lead-time items. Obtaining copper, shop space, and workers to fabricate replacement windings may take weeks or months. To avoid costly downtime of generators, operators may stock complete stators or complete sets of windings for specific series of machines. Other approaches are to stock three-quarters or one-half of a set of windings. Still other approaches are to stock one phase group, one of each shape of bar in a phase group, or a few top and bottom bars for the entire machine. An extreme position would be to stock nothing and depend on the manufacturer or a repair shop to come to the rescue.

Spare windings for rotors are not normally stocked; utilities rely on manufacturers and repair shops to repair or replace rotor windings.

WINDING SUPPLIES

These supplies are divided into long-shelf-life and short-shelf-life materials. Both types are required to install replacement coils or bars. Long-shelf-life materials are those that normally do not change characteristics during years of storage. Such

materials are wedges, fillers, side packing, ripple springs, blocks, roving, cords, solder, clips, hoses, and similar electrical and mechanical support items. Short-shelf-life materials are resins, varnishes, paints, glues, cements, and similar materials that may have shelf lives of only a few weeks or months.

Long-shelf-life materials can be obtained and stored with replacement coils and bars so that these items are on hand when required. Short-shelf-life materials can usually be obtained from manufacturers, repair shops, or other suppliers on short notice. Careful checks of these latter items should be made when they are received to ensure that the shelf life has not already expired or will not expire before the materials can be used.

ROTORS

Spare rotors have been purchased by utilities to avoid costly turbine generator downtime because of a rotor problem. Such rotors are a major capital expense, particularly for large generators. For utilities with several generators of the same series, the cost of a spare rotor can often be justified for protection of several units. Where there is only one generator involved, it may be difficult to justify the cost of a spare rotor. Factors that must be considered are operating experience and duty, design of the rotor, importance of the generator to the system, and the cost of replacement power.

ROTOR SALIENT POLES

Generators with salient-pole rotors can usually be protected from the downtime caused by rotor problems by stocking separate salient poles rather than complete rotors. These salient poles consist of the core, field winding, and dampers and are an entity that can replace a failed salient pole. Replacements are made by opening the electrical connections for the field and amortisseur windings between poles, driving out the support keys to the rim (or removing the bolts), and lifting out the pole. Replacements are made in the reverse order.

The number of salient poles that should be stocked depends on the frequency of failures, design of the pole, the number of poles on the rotor, and the operating duty. Generator/motors for pumped-storage duty are more prone to rotor problems when full-voltage or reduced-voltage induction starting methods are used because of the starting duty on the amortisseur and damper windings. Operators may therefore elect to stock

more spare salient poles for generator/motors than they would for generator-duty-only machines.

BEARINGS

Generator bearings range from ball bearings for small generators to roller bearings, sleeve or journal bearings of bronze (or steel shells with babbitted surfaces), huge turbine generator journal bearings, or hydrogenerator guide and thrust bearings.

Small bearings may be readily available from manufacturers or bearing supply houses, and it may not be necessary to stock such bearings. As sizes increase, however, operators may find it prudent to stock spare bearings. This fact is particularly true as the bearings become larger, require longer lead times, or come from overseas manufacturers.

Another approach is not to stock bearings and then replace, repair, or rebabbit bearings whenever damage is found. The major drawback to this approach is that long manufacturing lead times may be required if a bearing is completely destroyed.

Thrust bearings may be ball or roller bearings, continuous babbit with machined grooves to obtain an oil wedge, or segmented babbit shoes. The latter type may be pivoted or mounted on springs. Complete bearings can be stocked for the smaller-sized bearings; manufacturers or bearing supply houses may be useful for stocking such bearings. For the larger thrust bearings, shoes can be stocked that may have oversized babbit surfaces to permit final machining to correct sizes before installation.

OIL DEFLECTORS

Oil deflectors, or seal rings to some manufacturers, provide oil containment. They prevent lubricating oil from running along the shaft into the generator or away from the bearings. Oil deflectors are normally made of steel with a sacrificial insert material such as brass, bronze, or aluminum in a labyrinth configuration with a close-tolerance fit to the shaft. These items are usually stocked because of the close tolerances involved to keep the lubricating oil contained, the possibility that high vibration can damage the seal fit, and the possibility that a rough spot on the shaft can damage the seal surfaces. Axial expansion or contraction will often contribute to the latter possibility. Shaft currents can also cause damage to the oil deflec-

tors. Such damage occurs if the insulation that prevents the currents is inadequate, if it breaks down, or if it bridges over from contaminants such as carbon, dirt, or water.

HYDROGEN SEALS

Hydrogen-seal rings have either babbitted or bronze inserts in steel brackets for the surfaces next to the shaft. There may be one to three ring surfaces at each end of the generator, depending on the manufacturer. The rings are closely fitted to the shaft with only 0.005 to 0.010 in. of diametral clearance, depending on the shaft diameter. Seal oil of 6- to 12-psig pressure greater than the casing hydrogen pressure fills these small clearances and flows to hydrogen-side or air-side drains. With such small clearances, particles in the seal oil, loss of seal oil, axial expansion or contraction, and shaft currents can quickly destroy the seals. For these reasons, hydrogen seals are normally stocked as spare parts. Damaged seals may be repaired and returned to stock with oversized inserts to permit final machining after shaft diameters are checked.

1.17 LIST OF APPLICABLE STANDARDS

Following is a list of useful industry standards that are applicable to generators.

NEMA STANDARDS

- MG 1-1978 *Motors and Generators* (ANSI/NEMA MG 1)
- MG 5.2-1972 *Large Hydraulic-Turbine-Driven Synchronous Generator/Motor Units for Pumped-Storage Installations*

ANSI/IEEE STANDARDS

- 43-1974 *Recommended Practice for Testing Insulation Resistance of Rotating Machinery*
- 67-1972 *Guide for Operation and Maintenance of Turbine Generators*
- 95-1977 *Recommended Practice for Insulation Testing of Large AC Rotating Machinery with High Direct Voltage*
- 115-1983 *Test Procedures for Synchronous Machines*

- 115A-1984 *Trial-Use Standard Procedures for Obtaining Synchronous Machine Parameters by Standstill Frequency Response Testing*
- 286-1975 *Recommended Practice for Measurement of Power Factor Tip Up of Rotating Machinery*
- 421-1986 *Standard Criteria and Definitions for Excitation Systems for Synchronous Machines*
- 433-1974 *Recommended Practice for Insulation Testing of Large AC Rotating Machinery with High Voltage at Very Low Frequency*
- 492-1974 *Guide for Operation and Maintenance of Hydrogenerators*
- C50.10-1977 *General Requirements for Synchronous Machines*
- C50.12-1982 *Requirements for Salient-Pole Synchronous Generator and Generator/Motors for Hydraulic Turbine Applications*
- C50.13-1977 *Requirements for Cylindrical-Rotor Synchronous Generators*
- C50.14-1977 *Requirements for Combustion Gas-Turbine-Driven Cylindrical-Rotor Synchronous Generators*

APPENDIX A

Maintenance Forms

Generator Equipment Annual Maintenance Data

Plant _____ Unit no. _____ Date _____

MEGGER DATA: GENERAL OUTLINE FOR ISOLATION AND TESTING

Generator Stator

1. Check that complete generator clearance is in effect. _____
2. Open phase lead disconnects (if provided). _____
3. Open neutral ground disconnect or lead. _____
4. Disconnect regulator and/or metering transformers. _____
5. Check whether bus-duct cooling fan is operating (if applicable). _____
6. Check that stator cooling system is in service and conductivity is below 0.5 micromhos/cm (if applicable). _____
7. Relocate grounds temporarily if generator clearance is interfering with Meggering. _____
8. Megger test the stator winding to ground with 2500-V power-driven Megger. _____

30 s _____ 1 min _____ 10 min _____

Polarization index $\left(\frac{10 \text{ min}}{1 \text{ min}} \right)$ _____ Ambient temperature _____

Note: The Megger reading for water-cooled stators should be in the range of 1 to 5 MΩ, and only a 1-min reading is required.

Generator Field

1. Assure that generator is not on turning gear. _____
2. Remove field brushes and clean insulation. _____
3. Connect collector rings together. _____
4. Megger test the field winding to ground at collector rings with 500-V Megger. _____

30 s _____ 1 min _____ 10 min _____

Polarization index $\left(\frac{10 \text{ min}}{1 \text{ min}} \right)$ _____ Ambient temperature _____

Stator RTD temperature _____

Alternator Exciter Stator

1. Isolate stator from diode rectifier blanks. _____
2. Isolate stator from regulating equipment. _____
3. Megger test the stator winding to ground with 500-V Megger. _____

30 s _____ 1 min _____ 10 min _____

Polarization index $\left(\frac{10 \text{ min}}{1 \text{ min}} \right)$ _____ Ambient temperature _____

Alternator winding temperature (panel indicator) _____

Alternator Exciter Field

1. Check that alternator is not on turning gear. _____
2. Remove brushes and clean collector rings and insulation. _____
3. Connect collector rings together. _____
4. Megger test the exciter field to ground at collector rings with 500-V Megger. _____

30 s _____ 1 min _____ 10 min _____

Polarization index $\left(\frac{10 \text{ min}}{1 \text{ min}} \right)$ _____ Ambient temperature _____

Alternator winding temperature (panel indicator) _____

Direct Current Exciter

1. Open the breaker between the main exciter and main generator field. _____
2. Place the voltage-regulator control switch in OFF position. _____
3. Remove carbon dust and dirt from brush rigging and insulation. _____
4. Megger test the exciter field and armature to ground at brushes with 500-V Megger. _____

30 s _____ 1 min _____ 10 min _____

Polarization index $\left(\frac{10 \text{ min}}{1 \text{ min}} \right)$ _____ Ambient temperature _____

Winding temperature, if available. _____

Note: If 10-min Megger reading of field and armature is less than 0.5 MΩ, the windings and instrument wiring should be separated and Megger tested individually.

Stator Cooling-Water System Checks

1. Filters

Elements of _____ filter: Replaced _____ Inspected _____

Elements of _____ filter: Replaced _____ Inspected _____

2. Deionizers

Tank _____ Resin replaced _____

Tank _____ Resin replaced _____

3. Alarms

a. Stator cooling-water tank level low:

_____ inches below normal alarms _____

b. Stator cooling-water tank level high:

_____ inches above normal alarms _____

c. Stator cooling-water pressure low alarm. Pressure at generator

inlet _____ flow _____

- d. Stator cooling-water flow low alarm. Pressure at generator
inlet _____ flow _____.
- e. Stator water filter plugged alarm operates at differential pressure of _____.
- f. Stator cooling-water pump pressure low alarm closes on decreased pressure at _____ psi.
- 4. Trips
 - a. Stator cooling-water low-pressure trip. Pressure at generator
inlet _____ flow _____.
 - b. Stator cooling-water low-flow trip. Pressure at generator
inlet _____ flow _____.
- 5. Dual strainer inspection
_____ strainer in service-inspected. _____
_____ strainer in/out service-inspected. _____
- 6. Minimum flow stop on regulating valve at _____ gpm.
- 7. Stator cooling-water-tank pressure relief operates at _____ psi positive pressure and _____ psi negative pressure.
- 8. Stator cooling-water pumps start automatically:
_____ pump starts _____
_____ pump starts _____
- 9. Prestart-up stator water condition. With _____ deionizer in service and normal stator cooling-water flow, conductivity is:
Generator inlet _____ micromhos/cm
Generator outlet _____ micromhos/cm
Deionizer outlet _____ micromhos/cm

Miscellaneous Equipment Checks

- 1. Test water and oil leakage detectors.
 - a. Generator detector _____
 - b. Alternator/exciter detector _____
 - c. Hydrogen seal-oil enlargement detector _____
- 2. Check temperature-monitoring equipment.
 - a. Generator stator RTDs (if applicable):
 - (1) Megger test each to ground with 500-V Megger. _____
 - (2) Measure resistance of each with a bridge. _____
 - (3) Record ambient temperature. _____
 - b. Stator water outlet thermocouples (if applicable):
 - (1) Measure millivolts of each thermocouple. _____

- (2) Record ambient temperatures. _____
- 3.** Was generator degassed this outage? _____
- 4.** Generator collector rings and brushes.
- a.** Collector-ring condition checked. _____
 - b.** Collector-ring insulation cleaned. _____
 - c.** Brushes inspected and _____ replaced. _____
 - d.** Brush holders cleaned and pressure springs free to operate. _____
 - e.** Brush holders checked for alignment and tightness. _____
 - f.** Brushes checked for proper pressure and absence of brush hangup. _____
- 5.** Dc exciter brushes and commutator.
- a.** Commutator condition checked. _____
 - b.** Brushes inspected and _____ replaced. _____
 - c.** Brush holders cleaned and pressure springs free to operate. _____
 - d.** Brush holders checked for proper alignment and tightness. _____
 - e.** Brushes checked for proper pressure and absence of brush hangup. _____
- 6.** Alternator exciter collectors and brushes.
- a.** Collector-ring condition checked. _____
 - b.** Brushes inspected and _____ replaced. _____
 - c.** Brush holders cleaned and pressure springs free to operate. _____
 - d.** Brush holders checked for proper alignment and tightness. _____
 - e.** Brushes checked for proper pressure and absence of brush hangup. _____

Turbine Generator Inspection

Plant _____ Unit no. _____ Date _____

Nameplate Data

Mfr. _____ No. _____ Type _____

Volts _____ Speed _____ kVA _____ kW _____

Arm. amperes _____ Field amperes _____ PF _____ Psi H₂ _____

Exciter _____ Cycles _____ Phase _____ Inst. _____

Date of last inspection _____ Date made commercial _____

Type operation _____ Load cont. band _____

Reactive load _____ Stator RTDs _____

Extent of inspection _____

I. Stator Winding**A. General appearance**

1. Coil finish condition _____

2. General cleanliness _____

B. Coil condition in slots

1. Condition of wedges (A wedge sounding map is suggested.) _____

2. Wedge movement (EPRI EL-3358) _____

3. Evidence of coil looseness _____

C. Coil condition in end winding

1. Condition and tightness of blocks and spacers _____

2. Condition and tightness of cord lashing _____

3. Coil surface condition _____

4. Condition with respect to possible distortion _____

5. Compound migration _____

6. Insulation swelling _____

D. Evidence of corona or slot discharge distress

1. Condition of corona bridges _____

E. Tape separation or girth cracks

1. Extent _____

2. Nature (superficial or acute) _____

3. Chart observed conditions for future reference _____

F. Condition of core

1. Tightness of laminations _____
2. Cleanliness of ventilating ducts _____
3. Heating of finger plates _____

G. Bushings, bushing well, and buses

1. Cleanliness _____
2. Evidence of heating _____
3. Tightness of bus and current transformer connections _____

H. Insulation resistance

1. Megger voltage _____
2. Readings: 1 min _____ 10 min _____
3. Polarization index _____ Temperature _____

II. Rotor Windings (Field)**A. Visual inspection**

1. Condition of retaining ring fits and wedges _____
2. Condition of end-winding blocking _____
3. Condition of field-coil-connection lead and insulation _____
4. Condition of collector and collector insulation _____
5. Collector brush data: Mfr. _____ Grade _____
Size _____ No. used _____
6. Heating of wedges, retaining rings, or body _____
7. Condition of lead in studs _____
8. Mechanical looseness of parts _____

B. Electrical tests

1. Megger reading (500 V) _____ 1 min _____ 10 min _____
2. Polarization index _____ Temperature _____
3. Winding impedance at 60 Hz volts _____ amperes _____ ohms _____

III. Exciter

Mfr. _____ Serial no. _____ Type _____
Volts _____ Amperes _____

A. Armature

1. Condition of commutator and risers _____

2. Condition of winding insulation _____

3. Megger reading _____ Temperature _____
4. Exciter brush data: Size _____ Mfr. _____
Grade _____ Exciter poles _____ Brush boxes per arm _____
No. brushes used per arm _____ Comments _____

B. Field

1. Condition of coils _____
2. Tightness of connections _____
3. Megger reading _____ Temperature _____

C. Exciter housing

1. Severity of contamination and type _____
Comments _____

Inspection Report for Hydraulic Turbine Generators and Generator/Motors

Plant _____ Company _____ Unit _____ Date _____

Last inspection _____ Why this inspection _____

Generator/Motor Data

Mfr. _____ Serial # _____ Type _____ Date _____

kVA _____ PF _____ kW _____ Volts _____ Amperes _____

Field volts _____ Field amperes _____

Type of operation _____ MWh last year _____

Turbine Data

Mfr. _____ Serial # _____ hp _____ Head _____

Type _____ Speed _____ rpm Order # _____

Pump Data

ft³/s _____ hp _____ Head _____

Stator

Insulation class _____ Date of last rewind _____ By _____

General appearance: _____

Coil and end windings _____

Condition of core _____

Leads, buses, surge protection _____

Notes:

I. Stator Winding

A. General appearance

1. Coil finish, condition _____

2. General cleanliness _____

3. Severity of brake dust _____

4. Method(s) of cleaning _____

B. Coil condition in slots

1. Condition of wedges (A wedge sounding map is suggested.) _____

2. Axial movement of wedges or fillers (EPRI report EL-3358) _____

3. Vibration of wedges or fillers _____

4. Looseness of coils in slot _____

5. Evidence of corona discharge (indicated by whitish powder and corona erosion of insulation) _____

C. Coil condition in end winding

1. Condition and tightness of blocks and spacers _____

2. Condition and tightness of cord lashing _____

3. Coil surface condition
 - a. Paint _____
 - b. Evidence of corona discharge _____
4. Twisting or distortion of coils _____
5. Insulation swelling or spongy condition _____
6. Tape separations (openings in outer layer or armor tape, asbestos or glass tape) _____
7. Girth cracks _____

D. Condition of core

1. Tightness of laminations _____
2. Cleanliness of ventilating ducts _____
3. Evidence of core hot spots _____
4. Heating of clamping plates and fingers _____
5. Conditions of backiron _____

E. Bushings, buses, and phase rings:

1. Cleanliness _____
2. Evidence of heating _____
3. Condition of metering transformers _____

F. Stator insulation resistance (all phases to ground)

Winding temperature _____ Megger voltage _____

1 min _____ 10 min _____

Polarization index $\left(\frac{10 \text{ min}}{1 \text{ min}} \right)$ _____**G. Comments on stator condition and maintenance suggested or performed:**

II. Rotor

1. Insulation class _____ Date of last rewind _____
2. General appearance _____
3. Condition of coil surface and color _____
4. Evidence of coil movement _____

5. Condition of insulating collars, washers, and binding _____

6. Evidence of coil overheating _____
7. Condition of amortisseur bars and jumpers _____
8. Condition of slip ring leads _____
9. Fan blade mounting _____ Number of blades _____
10. Fan condition _____
11. Condition of rotor iron _____
12. Slip ring insulation type and condition _____
13. Slip ring material and condition _____
14. When is ring polarity reversed? _____
15. Total number of brushes _____ Grade _____ Mfr. _____
16. Brush size _____ Condition _____
17. Holder condition _____ Holders per arm _____
18. Field resistance in ohms _____ Temperature _____
19. Field impedance (120 Vac maximum) _____
20. Megger reading (500 vdc) 1 min _____ 10 min _____
Polarization index $\left(\frac{10 \text{ min}}{1 \text{ min}} \right)$ _____
21. Comments on rotor condition and maintenance suggested or performed. _____

III. Exciter

Mfr. _____ Serial # _____ Type _____
 Volts _____ Amperes _____ Type of drive _____
 Number of units served _____ Last rewind date _____

A. Armature

1. Condition of commutator and risers _____
2. Condition of winding insulation _____

3. Megger reading _____ Temperature _____

4. Brush data: Size _____ Mfr. _____ Grade _____
No. of poles _____ Total brushes _____
Brush life _____ Brush pressure _____
Brush problems _____

B. Field

1. Condition of coils _____
2. Tightness of connections _____
3. Megger reading _____ Temperature _____

C. Exciter housing

1. Severity of carbon dust _____
2. General condition _____

Notes: _____

Salient-Pole Rotor Inspection Sheet

Poles are numbered clockwise from slip ring leads on the nondriven end of the rotor.

Jumpers are described by the poles they connect (for example Jumper 7-8).

Operation rpm _____ Number of poles $\left(\frac{3600}{\text{rpm}} \times 2 \right)$ _____

Pole #	Condition	Pole #	Condition	Pole #	Condition
1		23		45	
2		24		46	
3		25		47	
4		26		48	
5		27		49	
6		28		50	
7		29		51	
8		30		52	
9		31		53	
10		32		54	
11		33		55	
12		34		56	
13		35		57	
14		36		58	
15		37		59	
16		38		60	
17		39		61	
18		40		62	
19		41		63	
20		42		64	
21		43		65	
22		44		66	

Data Sheet for Insulation Resistance (Megger Reading) of Rotating Machinery

Company _____ Location _____ Unit _____ Date _____

Time _____ Machine Serial No. _____ Manufacturer _____

Voltage _____ kVA or HP _____ Winding Temperature _____

Reason for test _____

Megger Manufacturer _____ Type _____ Serial No. _____ Voltage _____

Scale _____ Data by _____

OHMS/MEGOHMS INSULATION RESISTANCE TO GROUND

Time	Phase 1	Phase 2	Phase 3	Phases 1, 2, and 3	Megger Volts (Field 500-V maximum)
15 s	_____	_____	_____	_____	_____
30 s	_____	_____	_____	_____	_____
45 s	_____	_____	_____	_____	_____
1 min	_____	_____	_____	_____	_____
2 min	_____	_____	_____	_____	_____
3 min	_____	_____	_____	_____	_____
4 min	_____	_____	_____	_____	_____
5 min	_____	_____	_____	_____	_____
6 min	_____	_____	_____	_____	_____
7 min	_____	_____	_____	_____	_____
8 min	_____	_____	_____	_____	_____
9 min	_____	_____	_____	_____	_____
10 min	_____	_____	_____	_____	_____
PI	_____	_____	_____	_____	_____

PI = polarization index = $\frac{\text{10-min reading}}{\text{1-min reading}}$

Note: Water-cooled windings are to be tested under normal operating conditions of conductivity and flow; only a 1-min reading is necessary for water-cooled windings.

Data Sheet for AC High-Potential Test of Generators and Synchronous Condensers

Company _____ Location _____ Unit _____ Date _____

Machine Serial No. _____ kVA _____ Rated voltage _____

Reason for test _____ Data by _____

Test Set Used

Manufacturer _____ kVA _____ Maximum output voltage _____

Normal location _____ Serial Number _____ Output used _____

Machine voltage _____ Ambient temperature _____ Wet bulb _____

Test voltage $E_c - G$ _____ Barometer _____ % humidity _____

Air-density correction factor $K =$ _____

Corrected voltage $E_c - G$ _____ Machine temperature _____

Sphere diameter _____ Sphere gap setting _____

Sparkover voltage of above gap (1) _____ (2) _____ (3) _____

Gap for overvoltage protection _____ Gap sparkover voltage _____

Test Data

Time	Phase	Megger*	Test kV	Amps	Megger**	Notes
_____	_____	_____	_____	_____	_____	_____
_____	_____	_____	_____	_____	_____	_____
_____	_____	_____	_____	_____	_____	_____
_____	_____	_____	_____	_____	_____	_____
_____	_____	_____	_____	_____	_____	_____
_____	_____	_____	_____	_____	_____	_____
_____	_____	_____	_____	_____	_____	_____
_____	_____	_____	_____	_____	_____	_____

* Megger test reading before high-potential test

** Megger test reading after high-potential test

Motor, Generator, Synchronous Condenser Trouble Report

Company _____ Division or plant _____ Station _____

Date of failure _____ Time _____ Weather (if a factor) _____

Equipment designation _____

Nameplate Data

Mfr. _____ Voltage _____ hp/kVA _____ rpm _____ amps _____

Phase _____ Hz _____ Frame _____ S/N _____ Service factor _____

Enclosure: OPD _____ TEFC _____ WPI _____ WP II _____ EXP _____ Other _____

Other Data

Type bearing: ball _____ sleeve _____ forced oil _____ indoor _____ outdoor _____

Type insulation (class): A _____ B _____ H _____ F _____ other _____

Rated temperature rise (°C): 40 _____ 50 _____ 55 _____ 60 _____ 90 _____ other _____

Supplemental Information (Important)

1. Installation date _____ as new _____ used _____ rewound _____ rewound by _____ date _____

2. Loss of generating capacity _____ MW _____ h

3. Trouble discovered during installation _____ maintenance _____ service _____ other _____

4. Last disassembly and cleaning _____ inspection _____ air-gap check _____
bearing check _____ date _____

Last Megger reading _____ ohm/phase _____

5. Was there either an ensuing fire or explosion? _____ Is insurance claim being made? _____

Is equipment under warranty _____

6. Estimated means of repair _____

Estimated costs of repairs _____ By whom _____

7. What is normal load cycle for this equipment?

a. Amperes, max. _____ duration _____

b. Amperes, min. _____ duration _____

c. Amperes, normal _____ duration _____

8. Equipment type: dc, motor _____ generator _____ exciter _____

synchronous, motor _____ generator _____ condenser _____ induction motor _____

a. Type of failure (Mark all that apply.)

- | | |
|---|---|
| 1 _____ Stator winding | 9 _____ H ₂ seal |
| 2 _____ Rotor (field) winding | 10 _____ Cooler, H ₂ or stator water |
| 3 _____ Amortisseur winding | 11 _____ Commutator |
| 4 _____ Bus, bushing, lead, termination | 12 _____ Brush holder |
| 5 _____ Stator lamination | 13 _____ Brushes |
| 6 _____ Rotor lamination | 14 _____ Exciter |
| 7 _____ Retaining ring | 15 _____ Surge arrestor |
| 8 _____ Collector ring | 16 _____ Surge capacitor |

b. Cause of failure (Mark all that apply.)

- | | |
|---|--|
| 1 _____ Bearing failure | 16 _____ Operator error |
| 2 _____ Loss of lubricating oil | 17 _____ Insulation deterioration |
| 3 _____ Driven load vibration | 18 _____ Ground insulation failure |
| 4 _____ Motor vibration | 19 _____ Turn-to-turn insulation failure |
| 5 _____ Broken rotor bar | 20 _____ Coil vibration |
| 6 _____ Excessive moisture | 21 _____ Loose wedges |
| 7 _____ Water entered motor | 22 _____ Loose ties or blocks in end winding |
| 8 _____ Excessive dirt | 23 _____ Loose core or clamping fingers |
| 9 _____ Solid foreign material in motor | 24 _____ Core heating |
| 10 _____ Broken fan blades or other internal part | 25 _____ Lightning |
| 11 _____ Overload | 26 _____ Line surge |
| 12 _____ Driven equipment blocked | 27 _____ External fire or explosion |
| 13 _____ Protection or control not effective | 28 _____ Excessive ambient temperature |
| 14 _____ Regulator failure | 29 _____ Rodent damage |
| 15 _____ Excessive starts | 30 _____ Other |

9. Relay or protective device operation _____**a. For 13.8-kV, 4-kV, or 600-V switchgear**

(1) Settings found by calibration, after failure

(a) Overload relay _____ (b) Inst. relay _____

(2) Date of previous calibration _____

b. For motor control centers or local starter

(1) Overload heater, cat # _____, size _____, rating _____

10. Remarks (events leading to failure): _____

11. What was done with failed equipment? _____

12. How was replacement equipment secured? Where did it come from? _____

Replacement made by:

Report prepared by:

_____ Date _____ _____ Date _____

APPENDIX B

GUIDE FOR STORAGE OF SPARE

GENERATOR STATORS, ROTORS,

AND STATOR BARS

I. General

Common sense and discretion should be used in the storage of stators and rotors. The number of units involved are few, and their value is high. Because these units may be called upon at any time, they must be maintained in optimal condition. The following procedures should be carried out for the duration of the storage of a stator or a rotor.

Conditions for storing these units are not drastically different from general storage practices. A clean, dry area away from routine work areas and overhead cranes is preferable for storing these units. An important consideration is that small fluctuations in the temperature will cause condensation on the metal surfaces. The rate of corrosion increases exponentially with the increase of the percent of relative humidity. Therefore close control of temperature and relative humidity is very important in the storage of these units. A sample data sheet for recording the data is given for the rotor and for the stator.

II. Stators

A. Receiving

When a stator is received, it should be inspected by the owner and a manufacturer's representative for damage during shipping. If damage is found, it must be reported to

1. Transportation carrier
2. Utility headquarters
3. Manufacturer

The stator windings should be Megger tested and a polarization index measured according to the procedure outlined in the Megger testing section.

B. Storage Procedures

1. **Preparation** The stator should be stored on a raised platform, level and at least 1 ft off the ground. A coat of Tectyl 506 (trade product) or similar protective coating shall be applied to the support areas and all machined or unpainted surfaces before placement of the stator.

Any rusted areas should be repaired before the stator is placed in storage. A clean, dry area away from routine work areas and overhead cranes is preferable for storage.

2. **Enclosure** The stator must be sealed at each end with an endplate. An inspection window should be placed at each end for visually checking the condition of the desiccant bags. Megger test leads suitable for use with a 2500-V Megger should be attached to each stator winding terminal. Each lead should be

tagged to identify the terminal and phase. Approximately 200 lb of desiccant should be used in the stator: one-third should be placed in each end, and the remaining one-third should be supported from a line through the stator bore. The stator should then be sealed for storage under pressure.

3. **Atmosphere** The stator must be purged thoroughly with dry nitrogen. Nitrogen pressure inside the stator should be maintained between 0.5 and 1 psig. The bottle pressure supplying the nitrogen atmosphere should be 20 psig or greater. Once the bottle pressure goes below the 20-psig level, the bottle should be replaced. Pressure readings will be checked once per week. A pressure-drop test should be performed once the seal has been made in order to ensure that it holds the desired pressure.

4. **Relative humidity** Relative humidity must be maintained at 35% or less. The desiccant and nitrogen atmosphere will control the moisture content. A piece of untreated clean carbon steel (not stainless steel) may be used as a test piece to provide an early indication of corrosion. Relative humidity indicators should be placed inside the stator where they can be readily seen.

5. **Temperature** The temperature for the stator must be maintained at least 10 to 20°F above the ambient temperature of the building. This ambient temperature should never go below 40°F. Nonblower convection heaters could be used if necessary. These heaters should be thermostatically set for 50°F.

C. Megger Testing

A Megger is used to test the integrity of the insulation system. This procedure should be carried out once per month. The polarization index of the stator should be checked every six months. The polarization index of the stator is the ratio of a 10-min Megger reading to a 1-min Megger reading. The polarization index for a stator should be 2.0 or greater.

Each phase of the stator will be individually Megger tested with the other two phases and the stator frame grounded. Megger testing should be done with a 2500-V Megger (a 1000-V or 500-V Megger may be used, but these are not preferred). An acceptable Megger reading for each phase is 25 MΩ or greater. The megohm reading and the polarization index should be recorded on the data summary sheet. If a low Megger or polarization index

reading is found, contact the manufacturer for assistance.

D. Data Sheet

The following information must be kept for all spare stators in storage. A summary sheet shall be maintained to record all of the required data:

1. General:
 - a. Stator manufacturer
 - b. Serial number
 - c. Unit
2. Date received
3. Damage, as noted
4. Weekly measurements:
 - a. Nitrogen pressure (psig)
 - b. Relative humidity (%)
5. Monthly Megger measurement of each phase, 1-min reading
6. Six-month polarization index measurement
7. The attached form may be used to compile the measurements and information.

E. Renewing Procedure

Once it is determined that the relative humidity of the stator enclosure is above 35%, the following procedure should be followed. This procedure should only be performed on a day when the outside relative humidity is between 25% and 35%.

1. Purge the nitrogen to the outside atmosphere.
2. Remove the two manhole access covers at the top of either end of the stator.
3. Mount a portable air mover to the manhole access, and circulate air through the stator for 6 to 10 h.
4. Before entering the stator, be sure it is purged of nitrogen until a safe level of oxygen is established for the safety of personnel.
5. Recalibrate the humidity indicators.
6. Remove the old desiccant.
7. Place new desiccant in the stator bore. One-third of the desiccant should be placed on either side, and the remaining one-third should be supported from the cable at equal intervals.
8. Replace the steel test piece if necessary.
9. Reinstall the manhole covers and humidity indicators.
10. Purge the stator of air with dry oxygen.
11. Flush the stator windings and water manifolds with dry nitrogen if they are separately sealed off.
12. Refill the stator with nitrogen to a pressure between 0.5 to 1 psig.

III. Rotors

A. Receiving

When a rotor is received, it should be inspected by a headquarters engineer and a manufacturer's representative for damage during shipping. If damage is found, it must be reported to

1. Transportation carrier
2. Utility headquarters
3. Manufacturer

The rotor shipping crate should be opened to allow access to zippers, humidity indicators, desiccant pouches, and Megger connectors. Megger readings of 500 V and a polarization index measurement should be completed upon receipt according to the procedure prescribed in the Megger testing section.

B. Storage Procedures

1. **Preparation** Apply a coating of Tectyl 506 or similar protective coating to the journals, couplings, slip rings, and machined surfaces of the rotor. A second coat should be applied to the journals and hydrogen-seal areas. Any rusted areas should be repaired before the rotor is placed in storage. The rotor should be stored in a clean, dry area away from routine work areas and overhead cranes.

2. **Support and positioning** The rotor should be supported according to the drawing supplied by the manufacturer. If the wooden members of the skid appear to be deteriorating, the defective wood should be replaced.

The rotor must be positioned so that the pole faces will be vertically oriented. The north and south poles will be on top or bottom. The pole can usually be determined by observation.

The rotor body should be checked for sag when it is first received, and it should be set correctly into position. If it is determined that the sag is more than 0.5 in., the manufacturer should be notified. The deflection should be measured periodically if the rotor is going to remain in storage for a long period.

3. **Enclosure** The rotor should be stored with the storage bag tied around it with a cord. The bag will protect the unit from dust and dirt. The rotor should be housed inside a wooden frame covered with chicken wire and heavy plastic. The plastic sheets must be sealed tightly enough for the housing to prevent the internal air from mixing with large amounts of moist outside air. If any plastic sheets are damaged or punctured, they should be replaced as soon as possible. A piece of untreated clean carbon steel (not stainless steel) may be used as a test piece to provide an early indication of corrosion.

4. **Atmosphere** The relative humidity and temperature inside the housing should be closely monitored and controlled.

5. **Humidity** The relative humidity must be maintained at 35% or less and should be closely monitored. Dehumidifiers or desiccant may be used to maintain this relative humidity. It is suggested that desiccant bags be hung inside the housing even if dehumidifiers are used. The relative humidity should be measured at least

once per week to ensure that this level of 35% or less is being maintained.

6. **Temperature** An ambient temperature of 50°F minimum must be maintained in the storage building. Resistance heaters of approximately 3000 W should be used to keep the temperature inside the housing above 50°F minimum. In addition the housing may be illuminated; light bulbs will aid the heating of the internal atmosphere. The temperature of the housing should be checked at least once per week. The heated inside air can be circulated internally but should not be allowed to mix with moist outside air.

C. Megger Testing

Megger testing is used to test the integrity of the insulation system. The rotor field winding should be Meggered with a 500-V Megger. A polarization index of the rotor should be taken every six months. The polarization index of the rotor is the ratio of a 10-min Megger reading to a 1-min Megger reading. The polarization index for a rotor should be 1.2 or greater. The Megger reading and the polarization index will be recorded on the data summary sheet. The value of the Megger reading should be 2 MΩ or greater. If a low Megger or polarization index reading is found, contact the manufacturer for assistance.

D. Data Sheet

The following information must be kept for all spare rotors in storage. A summary sheet should be maintained to record all required data:

1. General:
 - a. Rotor manufacturer
 - b. Serial number
 - c. Unit
2. Date received
3. Damage, as noted
4. Weekly measurements of relative humidity (%)
5. Monthly Megger measurement
6. Six-month polarization index measurement
7. The attached form may be used to compile the measurements and information.

IV. Stator Bars

A. Receiving

When a shipment is received, it must be inspected for damage during shipping. If damage is found, it should be reported to

1. Transportation carrier
2. Utility headquarters
3. Manufacturer

B. Storage Procedures

The stator bars are shipped in a special skid package designed for long-term storage. The skid is enclosed by wood panels and should be backed with

either steel mesh or sheet metal for rodent protection. The panels are lined with weatherproof paper.

The following is a list of the storage requirements for the stator bars when they are kept in a heated building:

1. Leave the stator bars in the special skid provided.
2. Open the crate and inspect contents for damage and punctures. Do not open any airtight packages in which the bars are shipped.
3. Store spare stator bars in an area that is reasonably clean and dry.
4. Provide suitable fire protection.
5. Building heat must be at least 50°F to keep coils dry.
6. Store spare bars in areas away from traffic and possible damage from dropped equipment.

If storage is in a dry, clean, but unheated building, the following additional requirements have to be met:

1. Construct a wooden frame covered with chicken wire and heavy plastic.
2. Place enough thermostatically controlled space heaters inside the housing to maintain a temperature of 50°F. The heaters should be nonblower-type convection heaters.

C. High-Potential Testing Before Installing

Before the stator bar is installed, a high-potential test should be performed to ensure the integrity of the stator bar. The test can be either a dc or ac high-potential test. The ac test should be two times the rated voltage plus 1 kV. The dc test will be 1.7 times the ac value. The procedure is to wrap the bar in heavy foil and ground the foil to test the ground-wall insulation. If the bar does not pass the test, contact the manufacturer for assistance.

Checklist for Stator Storage

Manufacturer: _____ Building: _____ Unit: _____
Stator Serial No.: _____ Date Received: _____

Date/Time

Inside building
temperature/humidity

Inside stator
temperature/humidity/pressure

Winding pressure
(if available)

Winding insulation
measurements

W/2, 3, casing grounded
1-min Megger

2 W/1, 3, casing grounded
1-min Megger

3 W/1, 2, casing grounded
1-min Megger

1, 2, 3 W/casing grounded
1-min Megger

1, 2, 3, W/casing grounded
10-min Megger

Proper function of heaters and
pressure alarm

Comments and damage noted

Checklist for Rotor Storage

Manufacturer:	Building: Rotor Serial No.:	Unit: Date Received:
---------------	--------------------------------	-------------------------

Date/Time

Inside building
temperature/humidity

Rotor storage
(enclosure)
temperature/humidity

Field winding
10-min Megger

Field winding
1-min Megger

Proper functioning
of heaters and
dehumidifiers

Comments and
damage noted

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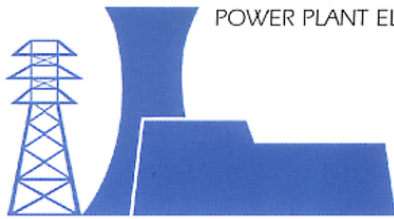
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